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LONG-TERM ENERGY OUTLOOK

1987 - 2005

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Preface

The Energy Market Analysis Division of the Department of Energy, Mines and Resources and its predecessors have produced long term outlooks for the demand, supply, and price of various forms of energy used in Canada since the mid-1970s. These have been used as a quantitative base for the development of policy analysis within the Department and as a framework upon which to examine varieties of competing assumptions concerning the energy sector's future in times of great change and continuing uncertainty.

From time to time these outlooks have been made available to interested parties outside the Department (most recently in 1984). The intention has been to provoke discussion of issues of concern, to promote informed debate, and to encourage feedback from the community to help improve the information base used as a starting framework for policy development.

The views expressed or implicit in this document are not necessarily those of the Government or of the Department, and no inferences should be drawn from this paper concerning the current or future status of any policy or program.

The versions of the long term outlook for the Canadian energy sector contained in this document were developed over a 6-month period to April 1988. The principal contributors were Al Coombs, Wally Geekie, Sushama Gera, Jai Persaud, Yvon Sabourin, Ram Sahi, Charlie Seeto, Fatma Sherif and Michel Théoret. Valuable assistance was provided by the Oil and Emergency Planning Branch, the Natural Gas Branch, the Electrical Energy Branch, the Coal Division, the Transportation Energy Branch and the Energy Programs Sector of this Department. Much of the work was undertaken under the direction of Pieter Brakel.

The tables in the appendices present a selection of the results of the outlook process. Further detail is available, and the Division would be happy to discuss any aspects of the forecast with interested parties.

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June 1988

(aussi disponible en français)

1. Executive Summary

Introduction

This document is a compendium of work which the Market Analysis Division prepared over a period of 6 months to April 1988 on Canada's long-term energy outlook. The individual components contain analysis of: a) long-term trends in the world oil market, b) associated implications for domestic energy prices, c) macroeconomic assumptions and demand for major types of energy by sector and region within Canada to the year 2005 and d) supply and net trade projections for each of the major fuels. Two sets of summary tables are provided in an appendix.

The results here presented are based on the use of the IFSD[1] modelling system. The IFSD Model is the central framework in a series of econometric, process, and accounting models, which together provide an integrated approach to the analysis of the medium- to long-term prospects for all energy markets in Canada. The estimates from these models are supplemented by information, comments and review provided by commodity specialists from other divisions in the Energy Programs Sector of the Department of Energy, Mines and Resources and by the views of experts from outside the Department. The final results incorporate and reflect the judgments of those in the Division who are responsible for their production.

Following are the main features of the analysis and outlook to 2005.

The World Oil Market

- Model simulations indicate that, under sustained U.S. $15/bbl (1986$) oil prices, demand for OPEC production is likely to begin to exceed capacity (estimated at about 30 MMb/d) by the mid- to late 1990s.

- At a level price of $30/bbl, demand for OPEC oil would remain in the 15-20 MMb/d range at least to the year 2000.

- The main swing producers in OPEC, as well as OPEC as a whole, would generate the highest discounted revenues under a scenario of initial low prices to recapture demand, followed by higher prices as production volumes swell.

- Accordingly, two base-case price scenarios were developed consistent with a low but rising pricing pattern.

- Base-case oil price scenarios (for WTI in 1986 U.S. dollars):

— $15-24 scenario: price per barrel level at $15 to 1990, rising to $22 by 1995 and to $24 by 2005.

— $18-32 scenario: price per barrel level at $18 to 1990, rising to $25 by 1995 and to $32 by 2005.

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1 The Inter-fuel Substitution Demand Model developed and maintained by the Department of Energy, Mines and Resources: See Sahi and Erdmann, " A Policy Model of Canadian Inter-fuel Substitution", in Ziemba, W.T., Schwartz, S.L., and Koenigsberg, E. eds., Energy Policy Modeling: United States and Canadian Experiences, Vol. I (Boston, 1980); and Halliwell and Sherif, "The EMR Energy Demand and Price Modeling System", in Kydes, A.S., and Geraghty, D.M. eds., Energy Markets in the Longer Term: Planning under Uncertainty, (Amsterdam, 1985).

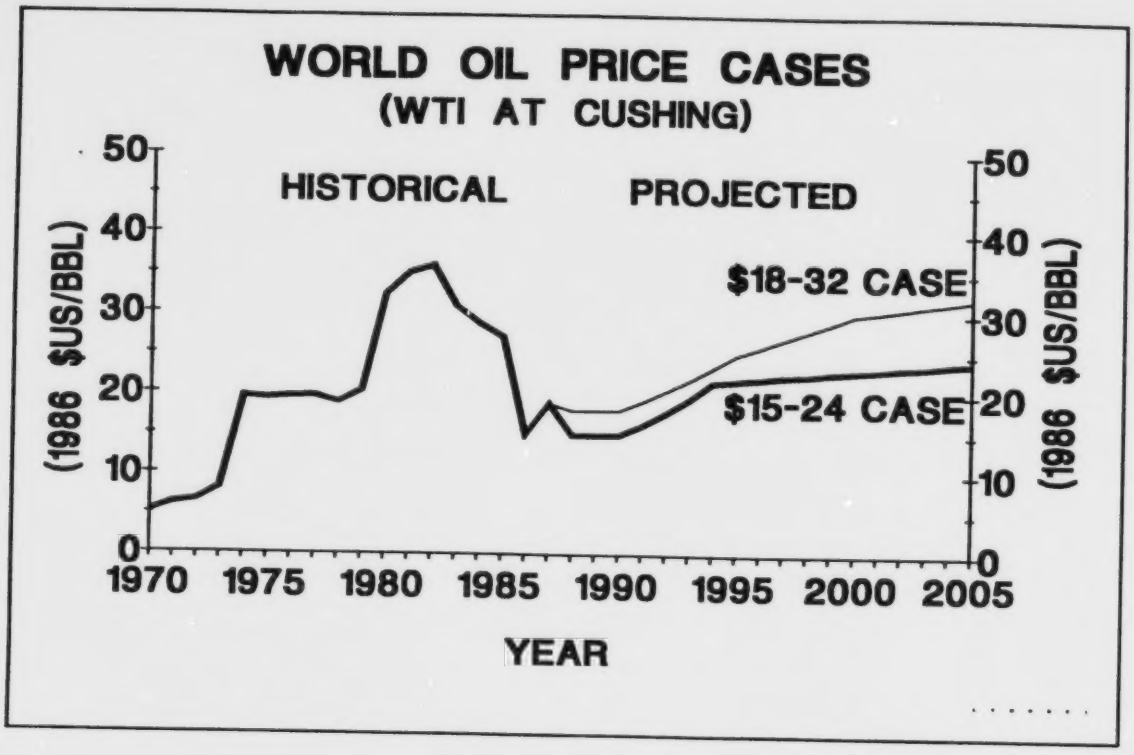

CHART 1.1

Domestic Fuel Prices

- Oil
  - Domestic price levels are tied directly to international prices adjusted for the exchange rate.
  - Price differentials between heavy and light rise from about U.S. $3/bbl (1987$) in 1987 to $5-6 in the 1990s, then are capped to reflect considerations relating to upgrading opportunities.
- Natural Gas
  - Price parity ratio between gas and oil at Toronto is in the 85-90 per cent range in the $15-24 scenario and averages 80 per cent in the $18-32 scenario.
- Electricity
  - Utility rates rise at just under the rate of inflation, on average, through 2005, due in part to generally moderate incremental capacity requirements in early years.
- Coal
  - Prices remain flat in real terms through the projection period.

Domestic Energy Demand

- Projected energy intensity (total secondary demand/RDP) declines modestly under both price scenarios, partly in response to the delayed effects of past conservation efforts and partly from the projected oil and gas price rebounds.

- Some substitution away from oil continues, particularly in the $18-32 scenario, where RPP demand rises by one per cent annually compared to total energy demand growth of about 1 1/2 per cent. (The comparable figures for the $15-24 case are just under 2 per cent for oil and just over 2 per cent for total energy.)

- Electricity's share of total energy demand rises by the largest amount, increasing from 23 per cent in 1986 to 25 1/4 per cent in 2005 in the $15-24 case and to 27 per cent in the $18-32 case.

Oil Supply and Trade

- Under both price scenarios, oil supply is projected to decline until the mid-1990s, then rebound over the balance of the projection period to 2005.
  - — In the $15-24 case, supply rises back to its 1987 level of about 1.6 MMb/d.
  - — In the $18-32 scenario, supply reaches 1.9 MMb/d in 2005.

- The share of conventional light and medium production in total supply falls from about 2/3 in 1987 to around 1/3 in 2005.

- Heavy oil supplies including bitumen are projected to rise by 135 Mb/d in the $15-24 case and by 260 Mb/d in the $18-32 case between 1987 and 2005.

- The lower-price scenario would retard the assumed development of non-conventional supplies in the case of virtually all major projects.

- In both scenarios, Canada is a growing net importer of light oil, with imports rising from less than 10 per cent of total oil demand in 1987 to about 20 per cent in the $18-32 scenario and to over 30 per cent in the $15-24 scenario by 2005.

- In the high-price scenario, Canada remains self-sufficient in total oil, while in the low-price case, net overall imports attain a level in the range of 15 per cent of total demand.

Gas Demand and Supply Potential

- Domestic demand is projected to rise from 1.8 TCF in 1987 to about 2.6 TCF by 2005 in the high-price case, and to 3.0 TCF in the low-price case.

- With export demand projected at 1.3-1.5 TCF annually in the 1990s, Canada's supply capability would just cover total (domestic and export) demand in the $15-24 case by the end of the period, while in the high-price case, substantial surpluses would remain. There is a possibility of much higher gas exports than is assumed here, if the pipeline system is expanded and frontier gas, such as from the Mackenzie Delta, is connected.

Electricity Capacity and Generation

- Electricity generation is projected to increase at an average annual rate of about 2.6 per cent.
- Due to the existence of current surpluses, generating capacity can be expanded at a slower average rate of about 2.2 per cent annually, while still comfortably meeting adequate reserve margins.
- The shares of capacity by different fuel types do not differ significantly between 1986 and 2005, although the nuclear share first expands and then contracts, as Darlington is completed and no further nuclear plants come on stream before the early 2000's.
- Exports of electricity are expected to stay at current levels until the early 1990's before increasing slowly to 2005, reflecting the continuing sale of near-term surpluses and the efforts of Hydro-Quebec to develop its U.S. market over the longer term.

Coal Production and Trade

- The outlook for demand for Canadian coal hinges on a number of critical factors including the following:
  - Ontario Hydro's generation expansion plans after 1992;
  - Environmental concerns and the legislation of emission standards;
  - International competitiveness of Canadian coal.
- Nonetheless, significant production gains in the order of 3 1/2 per cent annually could be realized.

Implications of the Outlook and Analysis

The outlook for the various fuel sectors of the Canadian economy does not reveal the emergence of any major disturbing imbalances under either of the price scenarios used in this analysis. It indicates a tendency to rely more extensively on light oil imports, to increase substantially heavy oil production and to use up surplus supply capabilities in the natural gas sector. On the demand side, past conservation efforts and off-oil switching trends are expected to continue, though at a much slower pace. In the electricity sector, no major discontinuities in demand growth or fuel input shares appear in evidence. For coal, the long-term outlook is relatively favourable, though clouded with major uncertainties.

The principal shortcoming of long-term projections of this nature is that they necessarily obscure ups and downs in individual markets, unanticipated events, periodic political and economic upheavals, technological breakthroughs, behavioral thresholds and so on. Nowhere is this problem more evident than in the assessment of the world oil market, which forms the basis of these projections. Suffice it to say that the analysis reveals underlying trends apparent only at a particular moment and requires constant review and reassessment as circumstances change.

2. World Oil Market and Outlook for Oil Prices

Introduction

Most projections of world oil prices made in the late 1970s and early 1980s turned out to be inordinately high. It was assumed that oil prices would continue rising in real terms at significant rates from their high levels at the time, while their effects on oil demands and supplies were virtually ignored. Assessing the world oil market by analyzing future oil supply and demand is likely to improve the understanding of the dynamics and potential behaviour of world oil prices.

Any approach to forecasting the oil market must also take account of the behaviour of OPEC. A complete collapse of OPEC would result in oil prices in the range of $5-10 for the short to medium term, at least until some of the current surplus production capacity of almost 10 MMb/d was worked off. What is required is a world oil model, in which both supply and demand are responsive to price, and which is useful for analyzing the cartel's behaviour. What are the optimal strategies for the OPEC countries? Are these strategies consistent for the diverse interests of OPEC members? The new approach used by EMR, and recently by some oil companies, is an attempt to address such questions.

Background and Recent Developments

Some background is necessary for an understanding of the new approach. World oil demand grew rapidly prior to 1974, with total world growth at 7.9 per cent per year from 1967 to 1973. This growth rate declined dramatically to only 2.0 per cent per year from 1973 to 1979. Following the second oil price shock, world demand dropped at an annual rate of 1.5 per cent to 1985, before rebounding by an average of 2.4 per cent per year in 1986 and 1987 as a result of the drastic price decline early in 1986. The Centrally Planned Economies (CPEs) had higher oil demand growth rates in all of the above periods before 1985, but they followed the pattern of declining rates of growth.

On the supply side, non-OPEC, non-CPE oil production started to rise in 1976, following the first oil price shock of 1973. From 1976 to 1985, this output increased by an average of 1.0 MMb/d every year, with production increasing from 16.3 MMb/d in 1976 to 25.4 MMb/d in 1985. In 1986 this production fell by about 0.3 MMb/d in response to lower oil prices, but it rebounded to the 1985 level in 1987. In contrast, OPEC production remained relatively stable from 1976 to 1979 as continuing increases in world oil demand were matched by increasing non-OPEC production. After 1979, however, the continuing increases in non-OPEC production combined with falling world demand to reduce the requirement for OPEC oil to 17.2 MMb/d in 1985, compared to 31.5 MMb/d in 1979. Following the dramatic price decline, the requirement for OPEC oil[1] rebounded to 19.5 MMb/d in 1986 and 1987 (see Chart 2.1)

The implication of the much lower rate of oil demand growth and vastly increased non-OPEC output is considerable surplus capacity in the late 1980s. Real price declines of 31 per cent from 1981 to 1985 were in-

1 Including Natural Gas Liquids (NGL's).

sufficient to bring supply and demand back into balance. The resulting situation forced OPEC to institute ever stricter production restraints and led to the dramatic fall in 1986. The immediate responses of both demand and supply to sharply lower prices in 1986 were very modest, with demand up only 2.9 per cent, and supply off less than 1.0 per cent. With prices in 1987 at close to OPEC's target of $18 (about $19.50

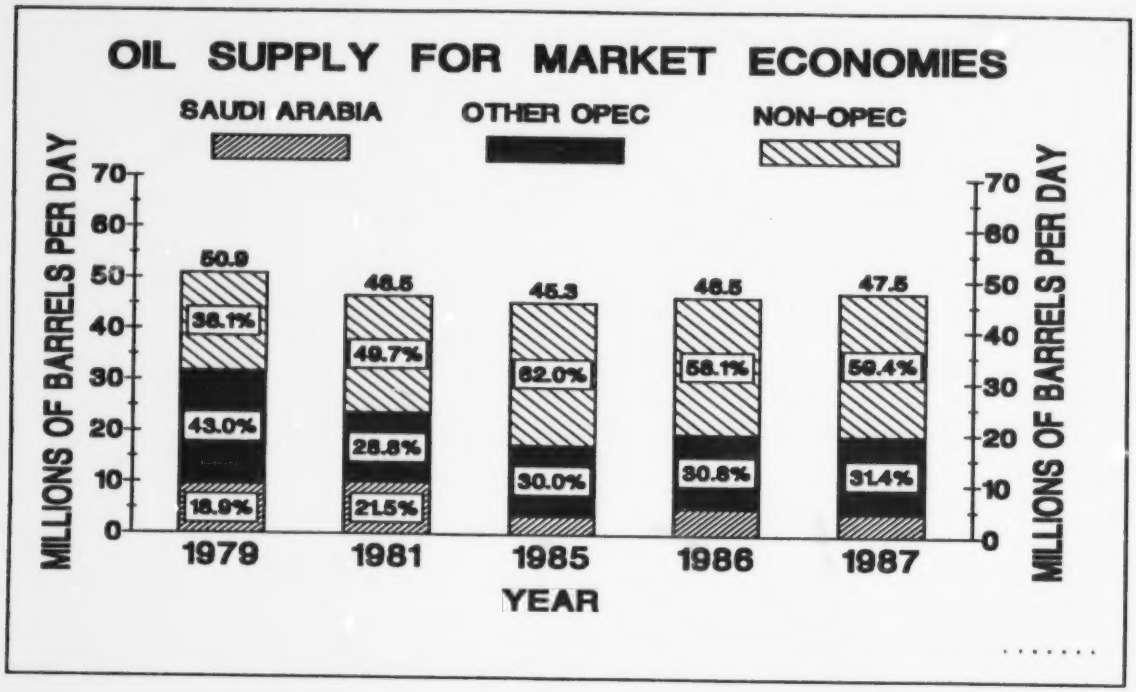

CHART 2.1

for WTI at Cushing), the outlook for rapid demand growth and supply curtailment is poor. The $18 price level is high enough to discourage a swing back to residual fuel oil as a boiler fuel and to enable many non-OPEC oil production projects to go ahead.

Forecast Methodology

EMR has developed a cartel behavioral framework to assess some possible scenarios of future oil prices. The framework analyses the present value of discounted future revenues for different groupings of OPEC producers such as Saudi Arabia, Gulf OPEC and total OPEC. To do the calculations, EMR uses a modified

version of the Data Resources Incorporated (DRI) World Oil Model.[1] This model calculates oil demand for several major developed economies using econometric equations which contain variables such as gross national product, oil prices, exchange rates, and inflation. World oil prices and oil supply are pre-determined or exogenous. Assumptions about the exogenous variables are made, and the model results for supply/demand balances are checked for plausibility.

This modified model has been used to examine the results for several flat price scenarios, largely to examine the properties of the model, and also for two plausible rising-price scenarios. The demand and supply price elasticities were set to approximately -0.45 and +0.4 respectively, with the supply elasticities for the U.S. and Canada being somewhat higher than average because they are higher-cost suppliers than most other countries.

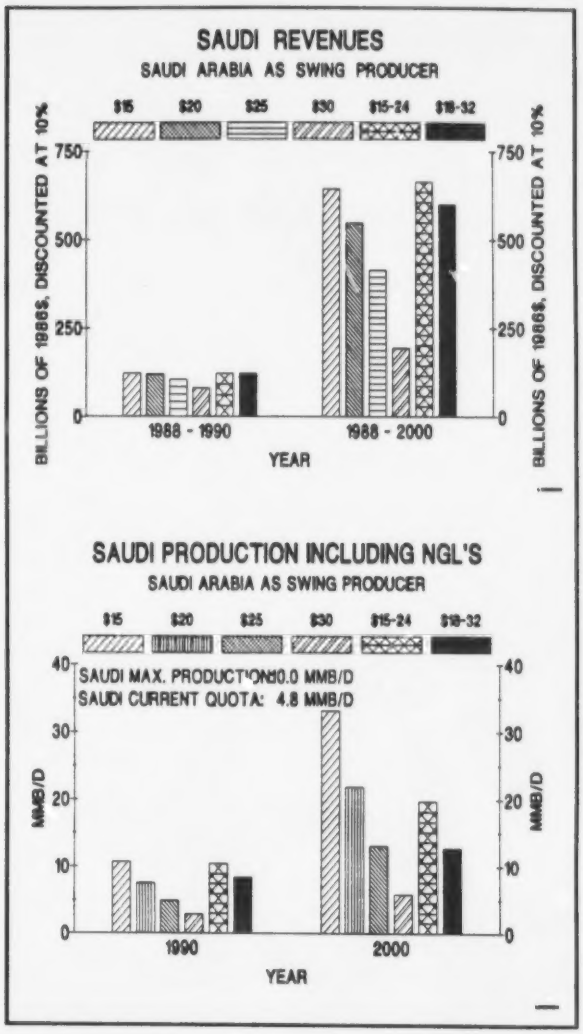

CHART 2.2

We have used the model to attempt to answer the questions posited in the introduction. What are the optimal strategies for the various countries within OPEC? Who are interested in high prices? Is it in the longer-term interests of some OPEC members to maintain relatively low prices for several years? The results of our experiments to date are given below, followed by some qualifications which we think are important at this stage of our work.

Model Results

The flat-price scenarios chosen were $15, $20, $25 and $30 per barrel, all in constant 1986 U.S. dollars.[2]

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1 In the past two years, the model was modified at EMR to give some price responsiveness to oil supply. This task was accomplished by adding some additional equations which generate reasonable price responses about DRI's base case supply projections. In addition to this modification, some changes were made in the demand elasticities for France and Japan. To help with the interpretation of the results, a set of routines were added to show the required production and implied discounted revenue streams if Saudi Arabia, Gulf OPEC (including Saudi Arabia), or Total OPEC were to act as swing producer(s), with all other OPEC members remaining at their current quotas.

2 Unless otherwise stated, all prices in this chapter are in 1986 U.S. dollars.

The model results for the flat $15 case gave implausible levels of total OPEC production within a few years, with production at 24.6 MMb/d by 1990 and 34.8 MMb/d by 1995. Clearly, a sustained price of $15/bbl is implausible beyond the next few years, without making some very heroic assumptions regarding demand or non-OPEC supply. Similarly, a price of $30/bbl results in demand for OPEC oil of less than 17 MMB/D in 1990 and only 15.3 MMb/d in 1995. It is very hard to imagine that OPEC would remain united at such low levels of oil production. These two price scenarios essentially limit the range of plausible price scenarios to the year 2000, although for short periods of time it is certainly conceivable that prices may depart from this range.

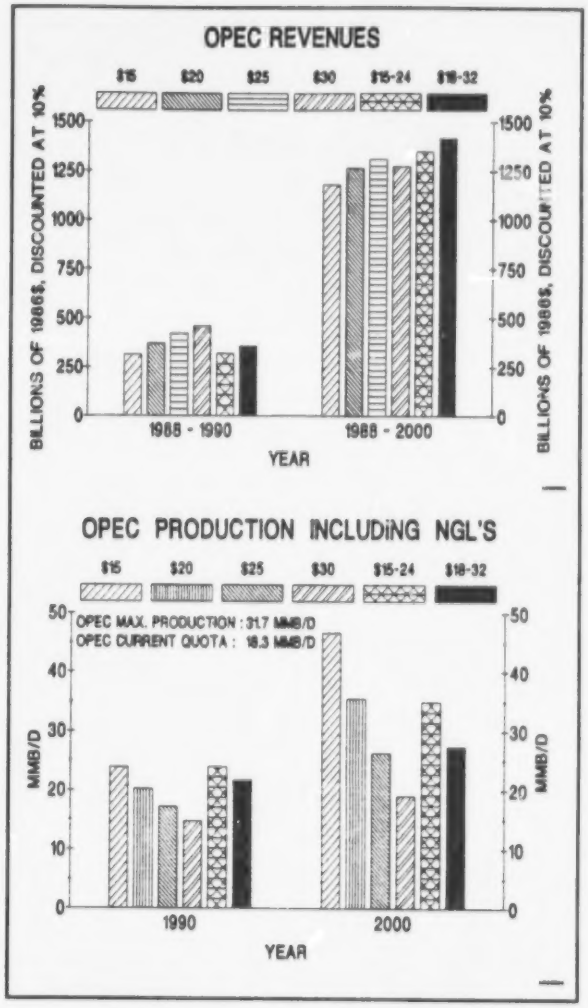

CHART 2.3

The $20 and $25 oil price cases are both possible in terms of supply and demand. However, the flat $20 price is not optimal in revenue terms for total OPEC and results in a call on OPEC of 35.8 MMb/d by the year 2000. It is difficult to envisage OPEC maintaining prices of $20 while called upon to produce substantially more than their current capacity (estimated to be about 28 MMb/d). The $25 oil price results in a more reasonable call on OPEC of 27.0 MMb/d in 2000, but it requires the production level to remain below the 1986 and 1987 level of 19.5 MMb/d until 1994. Such production levels do not appear plausible given the conflicts over production levels with the current quotas, which amounted to about 19.2 MMB/D at the time of the study.

These simulations suggest that, given the kinds of responsiveness of demand and supply which have been assumed, the most likely scenarios for oil prices over the years to 2000 are for somewhat lower prices (in the $15 to $20 per barrel range) for the near future, and rising real prices through the 1990s.

Two plausible cases which have been chosen for use in this study are the rising-price scenarios, $15-24 and $18-32, as shown in Chart 1.1. These scenarios, of low prices followed by gradually rising prices, enable OPEC to recapture market share in the next few years, in an environment of increasing demand resulting partially from the modest prices. In these scenarios, total OPEC production reaches 33.5 or 26.6 MMb/d in the year 2000, with the $15-24 and $18-32 price cases respectively. Discounted revenues are higher under these scenarios than under any of the flat-price cases, and required production rates in the short term are reasonable at 24.2 and 22.2 MMb/d respectively in 1990. These outcomes indicate that OPEC can be reasonably expected to establish a relatively stable market if they adopt such a strategy. Charts 2.2 and 2.3 show the model results graphically

for both Saudi Arabia and Total OPEC: both are in the range of plausible revenue maximizing strategies for Saudi Arabia and Total OPEC.

Qualifications

Several considerations could significantly affect oil markets and have different implications for oil price prospects. The base case for the model was provided by DRI, although some significant modifications were made to suit the views of EMR. Different views regarding the assumptions underlying the base case could lead to significantly different results.

The potential for fuel substitutability, particularly natural gas in Europe, the Soviet Union, and other countries around the world, may be higher than current estimates suggest. Coal will continue to compete with oil in the boiler fuel market with oil prices greater than $15 U.S. These substitution possibilities should be captured in the demand equations.

Another qualification is the impact of new technology. Developments started in the late 1970s and early 1980s, when oil prices were at their highest levels, are only now reaching maturity. It is possible that new technology, coupled with widespread forecasts of future oil price increases, will lead to continuing improvements in the efficiency of energy and oil use. The lagged effect (over time) of prices on the development and implementation of new technologies remains difficult to estimate.

On the supply side, non-OPEC production is now projected to remain virtually unchanged in the $18-32 case. This projection reflects upward revisions to our view on potential non-OPEC supply, but even it could be too conservative, given the discoveries in many parts of the world in the past few years.

Conclusions

The two price scenarios which we have used: $15-24 and $18-32 are reasonable ones. The $15-24 case appears to be somewhat on the low side, since the requirements for OPEC oil are expected to over-extend OPEC's willing productive capacity. However, all the above qualifications point to lower oil demands on OPEC. It is also in the interests of the Gulf producers, as shown in the study, to keep prices on the low side.

3. Domestic Energy Prices

Introduction

The price mechanism is the principle driving force which signals the need for markets to adjust to evolving supply and demand circumstances. Correspondingly, it is the key to the analytical framework employed by the Energy Market Analysis Division to develop energy supply and demand projections. There are two principal perspectives on energy price developments: the conceptual view of overall average energy prices and the relationship between different fuel prices or relative prices.

Oil Prices

Since the deregulation of oil prices and marketing procedures in Canada on June 1, 1985, Canadian oil producers have been able to negotiate sales contracts directly with crude oil purchasers. As a result, crude prices are market determined. Markets for Canadian crudes are concentrated mainly in the domestic market and in the U.S. Northern Tier. Exports of light crude to the U.S. compete in the Chicago markets with crudes such as WTI. The light crude price is therefore determined on the basis of its competitive value in Chicago. The key factors in the determination of domestic light crude oil prices are considered to be the following: 1) the WTI price in Chicago, 2) the crude price differential between Canadian light and WTI in Chicago and 3) the exchange rate.

The price of the reference light crude, Par crude, in Edmonton is expected to track the prices of WTI in Chicago adjusted for transportation costs, U.S. import tariffs, and the exchange rate. It is assumed that under both the $15-24 and the $18-32 price scenarios there is no differential between WTI and Par crude in Chicago.

Refiners' acquisition cost for crude in Alberta under both oil price scenarios is expected to grow by the same rate of growth as Par crude postings. Except for the Atlantic region, refinery cost of crude in the various regions is determined by the acquisition cost of crude in Alberta adjusted for the cost of transportation to the region. In the Atlantic region, the refinery acquisition cost of crude is determined by the cost of crude imports. Crude imports are based on the costs of importing North Sea Brent because more than half of Canadian crude imports are from the North Sea.

Oil Price Differentials

Oil price differentials between light and heavy crude oils are critical in analyzing potential domestic refinery investments and heavy crude oil and bitumen projects in Canada. For the outlook, the differential between light (38 API) and heavy (22 API) blends in Edmonton is expected to be limited by the cost of adding new upgrading facilities. In the short to medium term, this differential is expected to increase from its current level of U.S.$3/bbl to a range of U.S.$5-6/bbl. In this range, refiners, especially those in the U.S., would find it profitable to invest in upgrading facilities and prevent differentials from increasing above this range except for short periods of time.

Natural Gas Prices

The deregulation of natural gas prices in November 1986 has led to a sharp drop in gas field prices. The Alberta average field price declined by 26 per cent from $2.64/Mcf in October 1986 to $1.95 in November 1986. It continued its fall last year dipping to an average of about $1.70 for 1987. Large Canadian gas consumers have been able to negotiate directly with producers and are purchasing gas at a discount compared to prices paid by utilities for distribution into their core market.

The drop in natural gas prices is the result of the surplus deliverability of gas not only in Canada, but in all of North America, and the sharp fall in oil prices in 1986. Natural gas was deregulated at a time of excess production capability. The so-called North American gas bubble is expected to last at least until the end of this decade. This gas bubble has caused intense gas-to-gas competition in the U.S. and led to substantial discounts of spot gas prices against heavy fuel oil, the main competing fuel in the industrial market.

The largest single market for natural gas outside Alberta is the Ontario industrial market. Consequently, direct sales natural gas prices in Ontario are used as reference prices in projecting domestic natural gas prices. Direct sales prices are set at about 100 per cent parity (on the basis of efficiency-adjusted energy content) with industrial heavy fuel oil at the burner tip which, for the purpose of the outlook, is assumed to be equivalent to 110 per cent of the heavy fuel oil purchase price.

There may well be an array of different natural gas prices at the Alberta border which are dependent on the class of service, load factor and the nature and length of contracts. For the purpose of this outlook, it is assumed that prices for the various classes of consumers at the Alberta border converge to the average level of direct sales prices netted back to the Alberta border from Ontario. This is assumed to occur when long-term contracts expire or are re-negotiated.

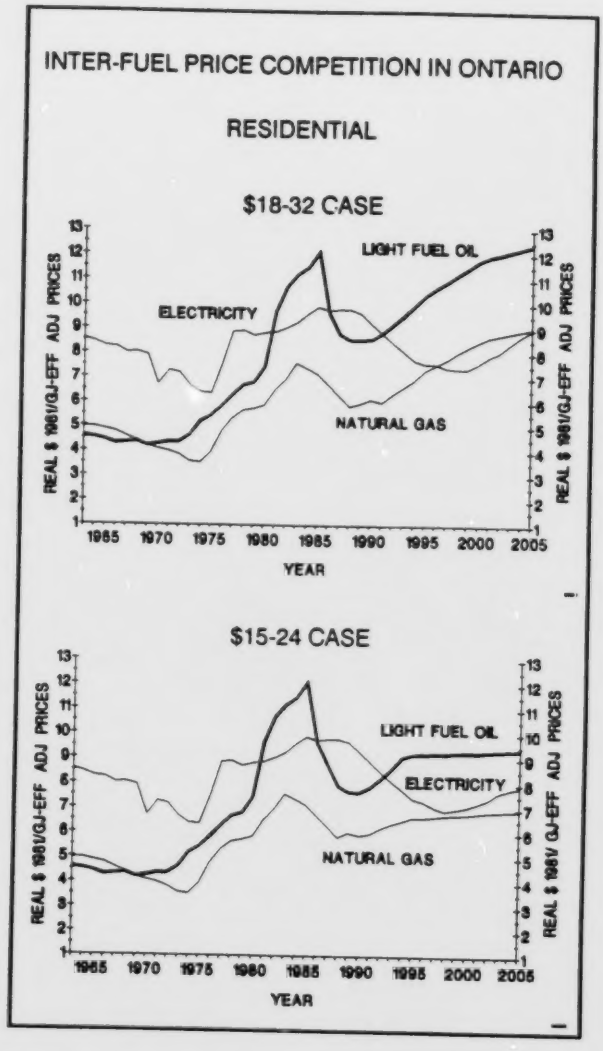

CHART 3.1

The above assumptions imply that after 1991 in the $15-24 scenario and after 1990 in the $18-32 scenario, natural gas prices for all classes of customers including exports are at the same level at the Alberta border. As a result, the parity between the average wholesale gas price and the refinery acquisition cost of crude

oil at Toronto in the 1990s averages 86 per cent and 80 per cent in the $15-24 and $18-32 scenarios respectively. By the year 2005, this gas/oil parity reaches 87 per cent in the $15-24 scenario and 85 per cent in the $18-32 scenario.

Electricity Prices

Electricity prices are expected to rise on average in both scenarios, but less rapidly than oil and gas prices over the projection period. The long-run average annual growth rate for electricity prices is expected to be less than the rate of inflation, around 3.1 per cent and 3.6 per cent in the $15-24 and $18-32 scenarios

Table 3.1

Selected End-Use Prices*

Average Annual Growth Rate (%)

	Oil Product		Natural Gas		Electricity	
	1986-1990	1990-2005	1986-1990	1990-2005	1986-1990	1990-2005
$15-24						
Ontario						
Residential	-1.3	6.0	-1.3	5.6	3.3	3.4
Industrial	-0.9	7.6	-4.0	7.3	3.4	3.4
Quebec						
Residential	-3.5	6.0	-2.3	5.5	3.2	3.4
Industrial	-2.9	7.6	-3.7	7.0	3.4	3.4
$18-32						
Ontario						
Residential	1.5	7.1	-2.2	7.3	3.1	4.4
Industrial	3.9	8.8	-1.4	8.8	3.2	4.4
Quebec						
Residential	-0.5	7.4	3.1	7.0	3.5	3.7
Industrial	3.2	9.3	-1.4	8.5	3.7	3.7

* Ontario and Quebec are chosen for illustrative purposes because of the high volumes of energy used and the intensity of inter-fuel competition.

respectively. This growth rate principally reflects a slowing in the construction of new facilities until more of the currently existing surplus capacity is gradually eroded. Average electricity prices in Canada rise relatively more rapidly after 2000 because of the requirement for new facilities at the beginning of the next century.

Coal Prices

Domestic coal prices are expected to drop in real terms in 1987 and remain flat in real terms in the long run. The reason behind this is twofold. First, thermal coal mines are mostly owned by electrical utilities in Canada. Hence the price for thermal coal is determined by the cost of production. These costs are not expected to grow in real terms. Second, most of British Columbia's metallurgical coal is exported to the U.S., while Ontario's requirements for this coal are met through imports from the U.S. U.S. coal prices have been forecast to remain weak in the long term. Domestic coal prices are therefore escalated at the rate of inflation in both oil price scenarios.

Relative Prices

Prices for different fuels may vary widely across regions and also for different applications within a particular region. The outlook for relative fuel prices reflects the different growth rates projected for the individual fuels (see Chart 3.1). In all regions, the relative price of electricity with respect to both natural gas and oil will decline in both scenarios. Table 3.1 provides the projected average annual growth rates for selected end-use prices in Ontario and Quebec for the $15-24 and $18-32 scenarios respectively.

Conclusions

Domestic crude oil prices are tied directly to international oil prices adjusted for exchange rates and transportation costs. Price differentials between light and heavy crude oil blends are expected to increase from U.S. $3/bbl in 1987 to a cap of U.S. $5-6/bbl (1987$) in the 1990's to reflect considerations relating to upgrading opportunities.

Prices for natural gas are in turn linked to domestic crude oil prices through natural gas and heavy fuel oil competition in the industrial sector in Ontario. Consequently, the parity between the average wholesale gas price and the refinery acquisition cost of crude oil at Toronto is in the 85 to 90 per cent range in the $15-24 scenario and in the 75 to 85 per cent range in the $18-32 scenario over the projection period.

Electricity prices are projected to increase at about 1 per cent below the rate of inflation on average over the projection period. This is less rapid than the rise in oil and gas prices. Coal prices are expected to remain constant in real terms.

4. Macroeconomic Assumptions

Introduction

This chapter reviews the main macroeconomic assumptions that underlie both the $18-32 and the $15-24 scenarios. These assumptions, coupled with the pricing assumptions discussed in previous chapters, are the key determinants of energy demand.

Macroeconomic assumptions in both EMR energy price scenarios are derived from Informetrica's macroeconomic growth forecasts (Post Workshop 1-87). Its short-term forecasts (1987-1989) were incorporated almost intact into EMR's high energy price scenario. For the long term (1990-2005), the cyclical movements contained in Informetrica's forecasts were smoothed out, EMR's aim being not to highlight specific downturns and upturns, but rather to indicate long-term trends.

National Outlook

The major assumptions underlying the macro forecasts are the following:

i) In the U.S.: steady growth in 1987 and 1988 (2.3 and 2.9 per cent respectively) and a milder downturn in 1990 (1.2 per cent) than originally expected. An acceleration of inflation due to tighter labour markets, increased oil prices and a depreciated dollar. As a result, a more restrictive monetary policy.

ii) The Canadian-U.S. exchange rate is assumed to be valued at 75¢ throughout the forecast period.

iii) Continued fiscal restraint on the part of the federal government and the implementation of phase I of the tax reform introduced early in 1987. Implementation of phase II (which would include some form of value-added tax) is not incorporated in the assumptions.

iv) Fertility rates to continue to decrease and survival rates to increase, albeit slightly. Small increases in participation rates are assumed to occur; immigration to remain low, by historical standards (70,000 annually through 1990, and 55,000 annually thereafter).

$18-32 Case

In the near term (1988-1989), the main stimulus to economic growth is expected to shift from consumption to non-residential investment and net exports.

Since 1982, steady decreases in the savings rate have kept consumer expenditures at levels sufficient to fuel economic growth. Over the next few years, however, the slippage in the savings rate should come to an end. Continued strength in the purchase of durable goods and increases in real wages should ease the fall in consumer expenditures growth. Beyond 1990, smaller real wage increases and lower housing starts and population growth are expected to push consumption growth down further.

Investment is expected to be robust in 1988, and only slightly less so in 1989. Lower investment in the auto industry will likely be replaced by increased investment in the oil and gas sector (with important implications for shifts in regional growth). Beyond 1990, investment is expected to drop, except in the oil and gas industry, where investment should respond positively to firmer and higher oil prices (see Table 4.1).

Housing starts in 1987 are estimated at 270,000 units. This figure ranks alongside those of the boom years of 1971-1978 and significantly exceeds the trend rate of increase in the number of households. After 1988, because of higher real interest rates, and more moderate increases in household incomes, housing starts will ease to reflect demographic requirements.

Table 4.1

Main $18-32 Assumptions
Average Annual Growth Rates (%)

	1986-1990	1990-2005
G.N.P.	2.5	2.0
C.P.I.	5.0	5.0
C.P.I. (excluding energy)	4.6	4.5
Employment	1.7	0.8
Population	1.0	0.6
Interest Rate (level) (10-year industrial)	(10.0)	(10.0)
Exchange Rate (level) (U.S.$/CAN$)	(0.75)	(0.75)
U.S. Wholesale Prices	3.5	4.5

The above factors suggest that GNP will grow at an annual average rate of 2.5 per cent in the near term (1986-1990), but will slow to approximately 2.0 per cent in the long term (1990-2005).

Inflation is assumed to be near or at the 5.0 per cent mark over the near and long terms.

$15-24 Case

In the $15-24 scenario, our assumptions are essentially the same as in the $18-32 scenario. To estimate the macroeconomic variables in this low case, world oil prices only were modified; everything else remained unchanged. The immediate impact of lower oil prices should be a lower inflation rate. Based on inflation rates in 1985 and 1986 and the share of energy in the consumer price index, we found that a one per cent increase in world oil prices results in a 0.028 per cent increase in CPI (1981 = 100). Other macroeconomic variables change in conjunction with the CPI. Consumers have more disposable income to spend on non-energy goods and services. Production costs are lower, and profits in the manufacturing industries are

therefore higher. As a result, investment in non-energy industries increases. On the other hand, energy industry profits fall, as does investment.

However, the increase in non-energy investment is greater than the reduction in energy investment. As a result, employment is higher in the low-case scenario than in the high-case scenario. Table 4.2 summarizes our macroeconomic assumptions in the low-case scenario.

Table 4.2

Main $15-24 Assumptions
Average Annual Growth Rates (%)

	1986-1990	1990-2005
G.N.P.	2.6	2.2
C.P.I.	4.3	4.3
C.P.I. (excluding energy)	4.6	4.5
Employment	1.7	1.0
Population	1.0	0.6
Interest Rate (level) (10-year industrial)	(9.7)	(9.4)
Exchange Rate (level) (U.S.$/CAN$)	(0.75)	(0.75)
U.S. Wholesale Prices	3.2	4.0

Provincial Outlook

Table 4.3 shows provincial growth rates over the short term (1986-1990) and long term (1990-2005). The short-term averages mask a narrowing of growth rates between provinces over the 1986-1990 period as investment slowly shifts from manufacturing in central Canada to resources in western Canada. The longer term holds a more equitable provincial distribution of economic growth.

In response to a weaker Canadian dollar (vis-à-vis European currencies), resource industries (particularly forestry and fisheries) are expected to boost short-term growth in the Atlantic provinces. In the medium and long terms, growth is more likely to come from energy investment: electricity in New Brunswick and oil and gas as well as electricity in Newfoundland.

To its advantage, Quebec is slowly loosening its traditional dependence on non-durables. Recent investments in the automotive and aerospace sectors should ensure more stable and reliable growth in future. Further expansion of its electrical power capacity can only enhance the provincial outlook.

The pace of Ontario's economic growth is expected to slow in the short run as U.S. demand slackens. In the longer term, our assumption is that Ontario's growth rate will be above average because of a recovery in exports and investment.

Table 4.3

Real Domestic Product by Province
Average Annual Growth Rates (%)

	1986-1990	1990-2005
($18-32 Case)		
Atlantic	2.3	1.7
Quebec	3.1	1.8
Ontario	3.1	2.0
Manitoba	2.3	2.0
Saskatchewan	2.4	2.4
Alberta	1.8	2.5
B.C. and Territories	1.8	1.8
($15-24 Case)		
Atlantic	2.6	1.8
Quebec	3.4	2.1
Ontario	3.2	2.3
Manitoba	2.8	2.4
Saskatchewan	2.2	2.4
Alberta	1.3	2.1
B.C. and Territories	2.3	2.0

The west is currently struggling with the negative effects of lower grain prices. This situation should be counterbalanced by improved prospects in the oil and gas industry. Over the near to medium terms, the metal mining industry in B.C. is expected to show moderate strength and the forest sector strong growth. In Alberta, diversification of the economy into the production of products with greater value-added, such as food processing, chemicals and wood products, should help to sustain growth.

Conclusions

In summary, real GNP in the $18-32 case is assumed to expand at an annual average rate of 2.5 per cent in the near term (1986-1990), but to slow to about 2.0 per cent in the long term (1990-2005). In the $15-24 case, real GNP is assumed to grow at a slightly higher pace.

5. Energy Demand Outlook

Introduction

The energy price increases of the 1970s and early 1980s have contributed to major changes in the pattern of energy use. Most of the adjustment to the upward price movements of the 1970s and early 1980s has already taken place in Canada. The key questions are: a) how much of this adjustment remains embedded in the system, b) whether there is any continuing momentum to declining energy intensity, and c) the extent to which the off-oil trend will continue. These questions have been analyzed using the updated version of the EMR's IFSD model. [Most of the model's equations were re-estimated on the basis of data extended to 1985, and the road transportation sector has been totally re-structured since the last public release of EMR demand projections.]

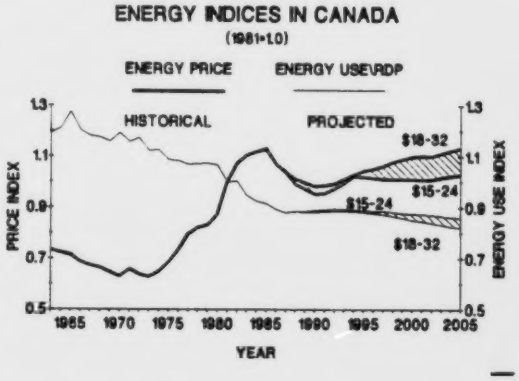

CHART 5.1

Aggregate Energy Intensity[1]

Chart 5.1 shows expected changes in energy intensity for both price scenarios over the next 20 years at the most aggregate level, as well as the experience of the past 20 years.

From 1973 to 1986, the index of energy use per unit of economic activity fell by over 20 per cent. From 1986 through 2005, price increases of the past as well as the future are expected to continue to have a significant effect. Energy use per unit of economic activity is projected to decline by about .5 per cent per year (Table 5.1). The effects of currently lower, but rising energy prices will begin to affect intensity trends with some lags.

Some changes in energy demands from increases in energy prices have lagged due to slow roll-over of capital stock. Although some progress has been made to shorten lags, it still takes five to 10 years for most of the effects of a price change to be felt in most sectors of the economy. Three factors have accelerated the response. First, energy costs now represent a larger share of production costs in the manufacturing industries and in family budgets than they did in the early 1970s. Consequently, there are greater incentives to undertake energy saving investments quickly. Second, greater choices of energy-using processes and technologies are available now than used to be the case. Third, energy users have been encouraged by grants and other incentives by governments and electric utilities in Canada, which have accentuated price impacts and accelerated the adjustment process. Recent

1 Energy intensity is defined as energy, measured in heat units, per unit of real activity (i.e., input GJs per unit of GDP).

econometric studies[1] have estimated increasing energy own-price elasticities after 1973, demonstrating that the higher energy prices have enhanced energy demand responses.

Historically high prices continue to affect energy intensity trends. Despite lower prices, energy intensity declines have continued. The current lower prices affect the medium-term projections of energy intensity

Table 5.1

Energy Demand*

Average Annual Growth Rate (%)

	1972/62	1986/72	1990/86	2005/86
$18-32 Scenario				
Secondary Energy Demand	5.5	1.1	2.1	1.6
Secondary Demand /RDP	0.0	-2.0	-0.5	-0.5
$15-24 Scenario				
Secondary Energy Demand	5.5	1.1	2.5	2.1
Secondary Demand/RDP	0.0	-2.0	-0.4	-0.3

* Energy demand for 1986 was normalized for weather in the calculation of the above growth rates.

with some lags. During the period between 1988 and 1995, energy demand per unit of economic activity is expected to be essentially flat. We expect the declines in energy intensity to resume at roughly one per cent a year when energy prices begin to rise in the early 1990s.

The upward trend in total energy demand, which resumed in 1984 after declines for a few years, is expected to continue under both price scenarios. Although energy demand increased only at a moderate rate of one per cent each year in 1986 and 1987 (partly as a result of warmer weather in those years), strong growth of 3.5 per cent is projected for 1988. Over the medium and longer terms under the $18-32 price scenario, total energy consumption is projected to rise at an annual rate of two per cent to 1990 and 1.5 per cent thereafter. In other words, by the year 2005, Canadians are expected to use almost 40 per cent more energy than in 1986. Under the $15-24 scenario, energy demand rises by 2.1 per cent annually, resulting in 50 per cent more demand by 2005.

1 "Productivity Trends and the Role of Energy in Canadian Industry", prepared by E. Berndt and C. Watkins for EMR, 1987.

Sectoral Experience

In general, the sectoral energy intensity patterns reflect aggregate trends. The major exception to this tendency in the past has been the industrial sector, where energy intensity declines were similar during both the periods of rising and falling prices. It should be noted that, while aggregate intensity reductions were moderate in this sector during the last seven years, the use of purchased fuels fell sharply as industries used more renewable sources of energy.[1]

Some increases in energy consumption per unit of output are projected for Canadian manufacturing industries in the short run. This increase in energy intensity stems mainly from relatively stronger growth in some of the energy-intensive industries, overall lower energy prices in the near term and relative price advantage for petroleum products compared to electricity, resulting in a higher share of oil[2] in total energy consumption (see Table 5.2).

Table 5.2

Average Annual Growth Rates in Intensities (%)

$18-32 Price Scenario

	1972/62	1986/72	1990/86	2005/90
Energy /RDP	0.0	-2.0	-0.5	-0.7
Residential/ Households	1.1	-2.8	-0.6	-0.3
Residential/ Real Disposable Income	-1.6	-3.3	-0.5	-0.4
Commercial/RDP	5.5	-2.9	0.2	0.0
Industrial/RDP	-0.7	-0.4	0.4	-0.3
Gasoline/KM	0.6	-1.5	-2.5	-1.1

With regard to the road transportation sector, the combination of higher prices and conservation measures has resulted in sharp improvements in new car efficiency. Further improvements in the efficiency of new automobiles are expected to take place over the next 20 years, but at a much lower rate due to reduced expectation of future prices. New car efficiency is expected to be flat during the next five years and modest

1 While the aggregate measures of industrial intensity show modest declines since 1973, disaggregate industry-specific measures of net energy efficiency such as energy required to do specific tasks show significantly larger conservation improvements. The net energy efficiency calculations exclude the effects of changes in the industrial structure and increased energy requirements due to environmental considerations. In the IFSD model, only the aggregate gross energy intensity is modelled.

2 The increased share of oil in total energy consumption raises energy intensity because of the lower conversion efficiency of this fuel.

gains of nearly one per cent are assumed thereafter (Chart 5.2). We note that there remains a great deal of uncertainty in forecasting the fuel efficiency of new cars. Some experts envision annual efficiency gains of as much as 1.6 per cent over the next several years.

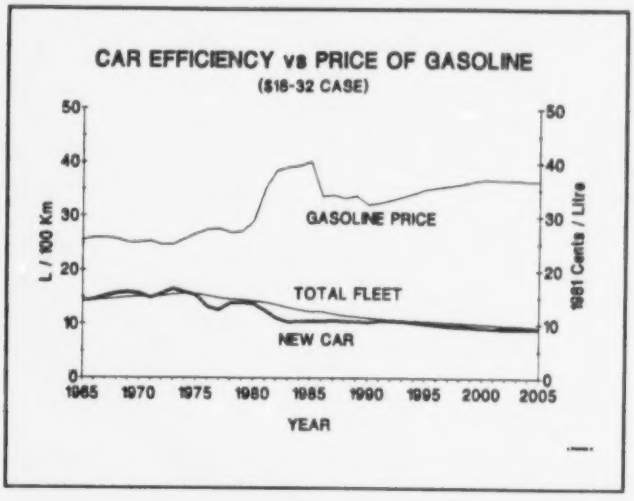

CHART 5.2

Of the three major components of motor gasoline demand, distance travelled per car is expected to remain essentially unchanged; the stock of motor vehicles is projected to grow at 1.8 to 2.0 per cent per year reflecting developments in demography, purchasing power and work force shifts, but at the same time, we expect that fuel efficiency of the car fleet will improve by 1.0 to 1.3 per cent per year, resulting in motor gasoline demand growth of 0.7 to 1.6 per cent per year under the two scenarios. Only limited penetration of alternative fuels (compressed natural gas and propane) is assumed in the road transportation sector. Although current use of ethanol, methanol and MTBE[1] is very limited in Canada, there exists potential for significant growth. As these fuels have higher octane content, environmental concerns such as lead phasedown and emission standards could result in significant increases in the use of these fuels.

Fuel Substitution

A central aspect of the overall energy demand outlook is the expectation of continuing substitution away from oil in all sectors except transportation. As in the case of intensity, the effects of absolute and relative price changes over the past 15 years combined with the expansion of the natural gas distribution system are expected to continue affecting choice of fuels in the future. Oil's share is expected to remain unchanged at 40 per cent during the rest of the 1980s, but with the anticipated rise of real oil prices in the 1990s, to decline to 35 per cent by 2005 under the $18-32 scenario, and 37 per cent under the $15-24 scenario. The decline will be matched by increases in the shares of natural gas and electricity (Chart 5.3). Electricity is projected to capture a rela-

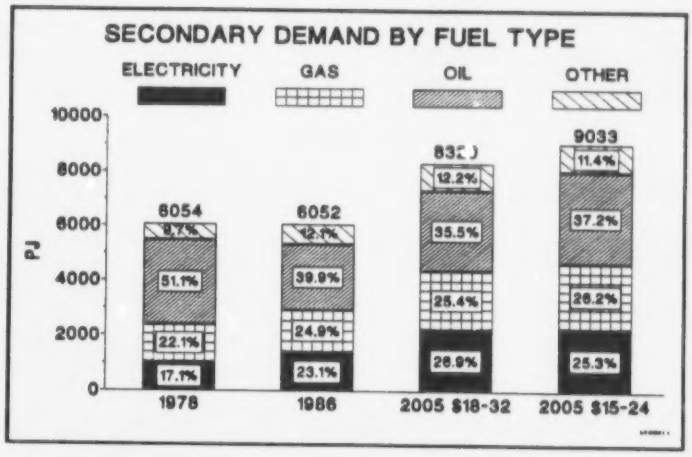

CHART 5.3

1 MTBE is methyl tertiary butyl ether and is used as octane booster in gasoline in place of lead.

tively larger share of the market in all sectors, due to expected declines in its real prices.

At the sectoral level, a significant degree of inter-fuel substitution will continue to take place in the residential sector causing the share of oil to decline to less than 10 per cent by 2005 (Chart 5.4). Most of this decline is expected to come from Ontario, Québec and B.C. In the short term, as oil maintains its competitive edge over natural gas and becomes more competitive with electricity, its share in the commercial and industrial sector is expected to increase marginally. Over the longer term, however, a modest decline in its share is projected (Chart 5.4). As use of renewables is projected to grow at half the rate of total industrial demand, their share is expected to decrease from the current 18 per cent to 15 per cent. Some experts foresee stronger growth in the use of renewables. We acknowledge that there remains some uncertainty in this area, and we plan to carry out further analysis.

The demand for <u>total</u> oil is projected to rise at the rate of about one per cent per year under the $18-32 price scenario, compared to about two per cent a year under the $15-24 scenario. These are moderate growth rates in the historical context. Oil demand increased by about 7.0 per cent a year in the 1960s, slowed down to 1.6 per cent per year from 1973 to 1979, then declined by an average annual rate of 6.6 per cent to 1983. Between 1983 and 1986, it was essentially flat and is estimated to grow by over three per cent in 1987. Most of this growth in 1987 came from heavy fuel oil, diesel and non-energy use followed by mogas. With the exception of the residential sector, all sectors experienced an increase in oil demand.

In the 1990s and beyond, although the share of oil in the commercial and industrial sectors is projected to decline, its use in absolute terms in these sectors is expected to increase. Diesel and heavy fuel oil increasing at 2.0 to 3.5 per cent a year would be major sources of growth in total oil demand. Demands for motor gasoline and aviation fuels are projected to increase only at moderate rates of one per cent, while light fuel oil will continue to decline.

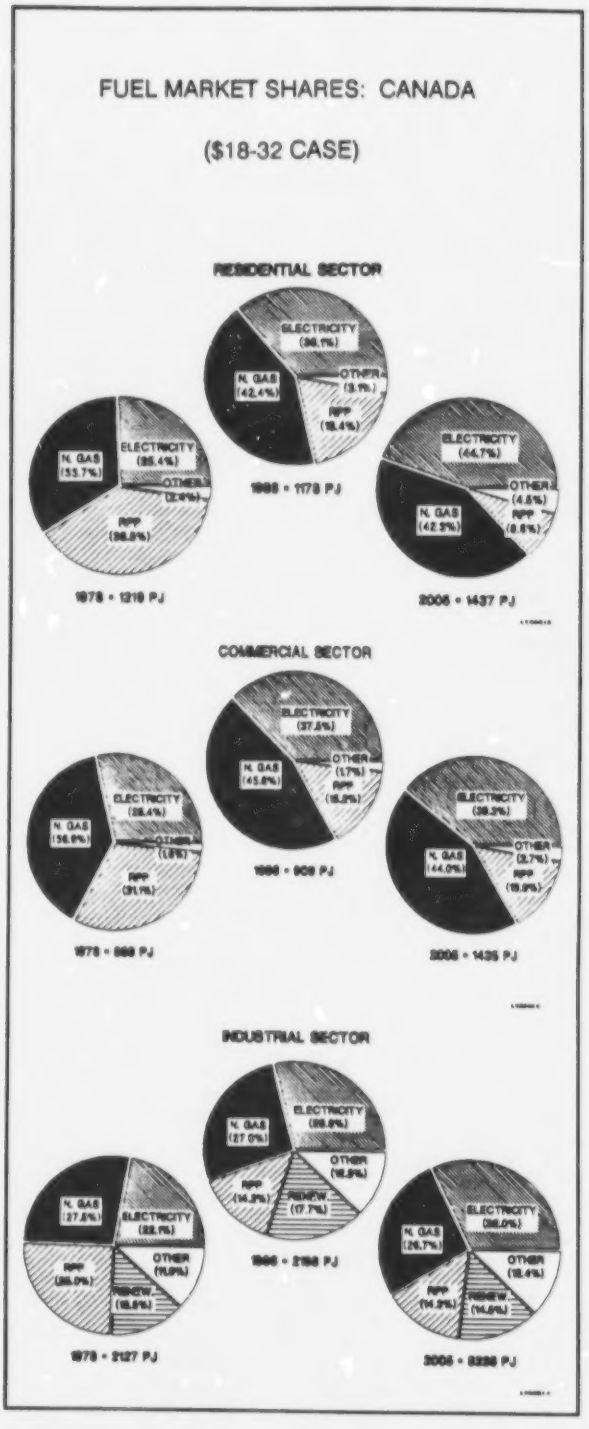

CHART 5.4

Natural gas and electricity demands are forecast to rise by an average 2.0 to 3.5 per cent per year over the next 20 years under both scenarios. Coal demand is also expected to rise by about three per cent a year.

Conclusions

- Although manufacturing industries will continue to be increasingly energy-efficient, the price declines of the recent past and near future are expected to result in small increases in the industrial sector energy intensity in the near term.

- In the longer run, energy-intensity declines and substitution away from oil to natural gas and electricity are expected to re-emerge, despite the substantially reduced expectation of future energy prices.

- The rise in economic activity and population will more than offset the effects of energy intensity reductions, resulting in increases in energy demand of between 1.7 and 2.1 per cent a year. By 2005, oil demand is projected to be 20 to 40 per cent higher than the current level, and increases for natural gas and electricity would be 40 to 60 per cent and 60 to 65 per cent.

6. Oil Supply and Trade

Introduction

Unlike energy demand analysis, in which econometric techniques are used to develop energy demand projections, projections of oil supply are based on an eclectic approach. All available information on geology, engineering and economic aspects of various potential supplies was assembled to arrive at oil supply estimates consistent with available evidence and with the forecasting framework. A modelling framework, the oil and gas supply impact model, was employed to ensure the overall consistency and reasonableness of the oil and gas supply estimates. The model relates the production and price levels to industry cash flow and thus to investment and ultimately to reserves additions. This ensures that projected supply can be achieved with funds available to the industry for investment purposes.

Crude Oil Supply

Despite the collapse of oil prices in 1986, crude oil production in Canada increased marginally to 1574 Mb/d, the highest level since 1979. Production in 1987 is estimated to be even higher at about 1631 Mb/d. The principal sources of this production increase are the elimination of light oil shut-in in the second half of 1987 and rapidly increasing bitumen production from projects such as Cold Lake and Wolf Lake.

Oil prices that Canadian producers receive under the $15-24 and $18-32 oil price scenarios are shown in Table 6.1.

The pace of conventional reserves additions is projected to be slower in the next 20 years, 1986 to 2005, than in the last 5 years (Table 6.2). In the short term, the pace of reserves additions is constrained by industry cash flow and by competition from profitable non-conventional projects for funds. In the longer term, estimates of remaining potential become more of a constraint.

Under the $15-24 price scenario, total crude oil supply is projected to decline from 1631 Mb/d in 1987 to 1340 Mb/d in 1995 before rebounding to 1630 Mb/d by 2005 (Chart 6.1 and Table 6.3). Under the $18-32 price scenario, total crude oil supply declines at a slower rate to 1560 Mb/d before rebounding to a much higher level of 1935 Mb/d in 2005 (Chart 6.2 and Table 6.3). In 2005, oil supply is about 300 Mb/d (or 19 per cent) higher in the $18-32 scenario.

The decline in production in the short to medium term reflects the decline in oil reserves additions and lower industry cash flow. The rebound in supply in the longer term is primarily the result of the continued development of new bitumen projects and the development of new higher-cost supplies from integrated oil sands plants and the frontier as oil prices increase significantly.

Table 6.1

Crude Oil Prices

Par Crude at Edmonton*

(1986 $/bbl)

	$15-24	$18-32
1987	23.62	23.62
1990	18.76	22.42
1995	27.35	30.99
2005	29.82	38.82

* Based on an exchange rate of $0.75 U.S. / $CAN.

Light Crude Oil

Conventional light crude supply, including pentanes, is projected to decline from 1071 Mb/d in 1987 at an average rate of 3.8 per cent a year to 535 Mb/d in the $15-24 scenario and at an average rate 3.3 per cent

Table 6.2

Conventional Crude Oil Annual Reserves Additions*

	Light Oil		Heavy Oil		Total	
	$15-24	$18-32	$15-24	$18-32	$15-24	$18-32
			(mmb)			
Annual Averages						
1981-1985	355.	355.	50.	50.	405.	405.
1986-1990	184.	212.	46.	48.	230.	260.
1991-1995	115.	140.	70.	74.	185.	214.
1996-2000	115.	140.	79.	83.	194.	223.
2001-2005	120.	145.	74.	78.	194.	223.
Total (1986-2005)	2670.	3184.	1345.	1415.	4015.	4500.

* Includes enhanced oil recovery.

a year to 590 Mb/d in the $18-32 scenario. There are insufficient reserves additions in the projection period to offset production from established reserves.

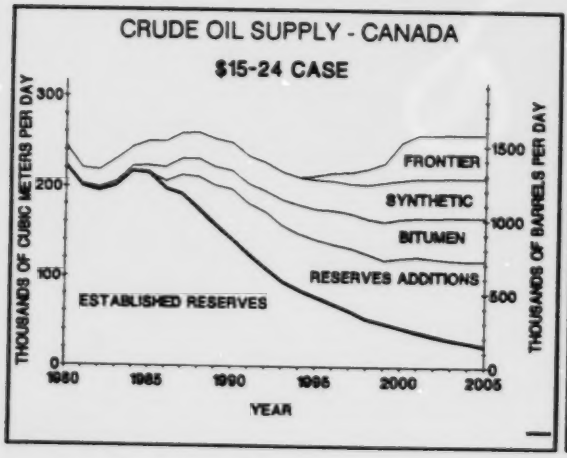

CHART 6.1

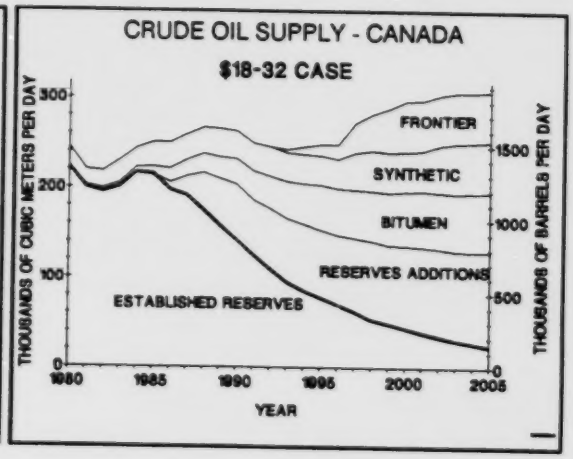

CHART 6.2

Heavy Crude Oil

Conventional heavy crude oil supply (conventional and bitumen) is projected to decline gradually from 268 Mb/d in 1987 to 210 Mb/d and 230 Mb/d in 2005 under the $15-24 and $18-32 scenarios respectively. This decline is, however, not as rapid as that projected for conventional light crude.

Table 6.3

Crude Oil Supply
(mb/d)

	Conventional		Oil Sands			
	Light*	Heavy	Bitumen	Synthetic	Frontier	Total
$15-24						
1986	1050.	247.	93.	184.	-	1574.
1987	1071.	268.	115.	177.	-	1631.
1988	1060.	268.	125.	179.	-	1632.
1989	1009.	258.	126.	195.	-	1588.
1990	989.	252.	129.	195.	-	1565.
1995	686.	204.	214.	205.	31.	1340.
2005	535.	210.	308.	274.	302.	1629.
$18-32						
1986	1050.	247.	93.	184.	-	1574.
1987	1071.	268.	115.	177.	-	1631.
1988	1091.	274.	132.	179.	-	1676.
1989	1049.	274.	151.	195.	-	1669.
1990	1019.	264.	176.	195.	-	1654.
1995	745.	220.	314.	205.	77.	1561.
2005	587.	229.	415.	352.	351.	1934.

* Includes pentanes plus and Norman Wells production.

Oil Sands

The resource base of oil sands deposits is enormous. The amount of oil that is potentially recoverable is equivalent to about 40 percent of total established world reserves. The principal methods for extracting oil sands from the ground are surface mining and in-situ recovery.

Synthetic light crude oil produced by integrated mining and upgrading facilities at the Suncor and Syncrude plants contributed about 11 percent of total crude oil production in 1987. The development of new plants requires large outlays of capital and a relatively long lead time of at least five years to plan and build the

facilities. In an environment of volatile oil prices, private project sponsors may need the commitment of governments to reduce or share the risk of the project being uneconomic. There has recently been a marked lowering of estimated costs for integrated oil sands. For example, the operating costs have been reduced from the range of $25/bbl to $30/bbl (1986$) in the early 1980's to below $15/bbl today. Moreover, future breakthroughs in technology could make these projects commercially attractive at even lower prices. The timing and the number of new plants included in this outlook represent a conservative view if there is a commitment by governments to oil sands development or a further lowering of project costs.

In the $15-24 scenario, a new plant with a capacity of 70 Mb/d is projected to start up in the mid to late 1990's. In the higher price scenario, $18-32, two new plants are projected to come on stream in the mid 1990's and the early 2000's. For the purpose of these projections, a major expansion at Syncrude is considered to be a new plant. In both scenarios, a minor expansion at Syncrude of 12 Mb/d is expected to start up in 1989. A minor expansion of 10 Mb/d at Suncor is expected to be operational in 1992 in the $18-32 scenario and in 1995 in the $15-24 scenario.

Bitumen supply from in-situ recovery, which has increased from 25 Mb/d to 115 Mb/d in just four years, is projected to increase very rapidly under both scenarios as additional phases of the Cold Lake, Wolf Lake and Peace River projects and new projects such as Burnt Lake, Lindbergh and Elk Point are brought on stream. By 2005, bitumen supply is projected to be 310 Mb/d and 415 Mb/d under the $15-24 and $18-32 scenarios respectively.

Frontier

The frontier regions are still relatively unexplored and only some ten percent of the estimated resource base has so far been discovered. Major crude oil discoveries have been made at Hibernia off the east coast and at Amauligak in the Beaufort Sea. Smaller accumulations have been found in the vicinity of these discoveries, as well as offshore Nova Scotia, in the Arctic Islands and in the MacKenzie Delta. To date there has been no production from any of these areas except for some demonstration tanker shipments. Some supplies from frontier discoveries are estimated to be economic if oil prices are in the range of U.S. $18 to U.S. $25/bbl.

In the $15-24 scenario, frontier production is projected to commence in the mid 1990's with modest volumes from the east coast and to increase to 300 Mb/d by 2005 as Beaufort production is brought on stream. In the $18-32 scenario, frontier supply is projected to commence a couple of years earlier and to increase more rapidly to 350 Mb/d by 2005.

Heavy Oil Markets

Blended heavy oil supply is projected to increase very rapidly over the projection period from about 453 Mb/d in 1987 (Table 6.4). By 2005, this supply is 640 Mb/d in the $15-24 scenario and 810 Mb/d in the $18-32 scenario. Market potential for heavy crude is expected to exceed supply over the projection period.

The domestic market for heavy crude oil is currently about 115 Mb/d. Without installation of new major upgrading facilities, this market is not expected to increase rapidly. Since it is assumed that price differentials will widen in the mid-1990s, an upgrader with a capacity 50 Mb/d is projected to commence operation in 1998.

Given the supply available for export in the $15-24 scenario, Canada's traditional export markets in the U.S. Northern Tier should be able to absorb available supply. Canadian heavy oil exports to the U.S. Northern

Tier are currently 350 Mb/d. With the further displacement of Mexican imports, declining Wyoming Sour supply and the addition of new upgrading facilities, market potential in the U.S. Northern Tier is estimated to be in the range of 450 to 500 Mb/d. In the $18-32 scenario, producers would therefore have to look for new markets beyond the U.S. Northern Tier to sell all their production after 2000.

Table 6.4

Blended Heavy Oil Supply/Demand Balance
(Mb/d)

	Supply*	Demand**	Export
$15-24			
1987	453.	114.	351.
1990	459.	193.	266.
1995	525.	203.	322.
2000	585.	219.	366.
2005	638.	242.	396.
$18-32			
1987	453.	114.	351.
1990	538.	182.	356.
1995	685.	189.	496.
2000	738.	242.	496.
2005	810.	254.	556.

* Includes diluent.
** Includes upgrader requirements.

Producers are already exploring new markets. Those considered to have good potential include Wood River, the Pacific Rim and the U.S. east coast. As prices are expected in the $18-32 scenario to be much higher than they are today, producers should be able to absorb the negative impact on netbacks resulting from exporting to these new markets.

A possible constraint on the increase of heavy crude oil supply, especially bitumen, is the availability of diluent. Given that producers are already investigating and implementing short-term solutions, diluent availability should not be a serious problem until the early to mid-1990s. Longer-term solutions being investigated by producers include diluent recycling from the U.S. Northern Tier, oil in water emulsions and the building of partial field upgraders.

Oil Trade

Under the $15-24 scenario, Canada is expected to remain a net oil exporter until 1990. By 2005, net imports are expected to be 241 Mb/d or about 13 per cent of total domestic demand (Chart 6.3). Under the $18-32 scenario, Canada is expected to remain self-sufficient throughout the projection period (Chart 6.4).

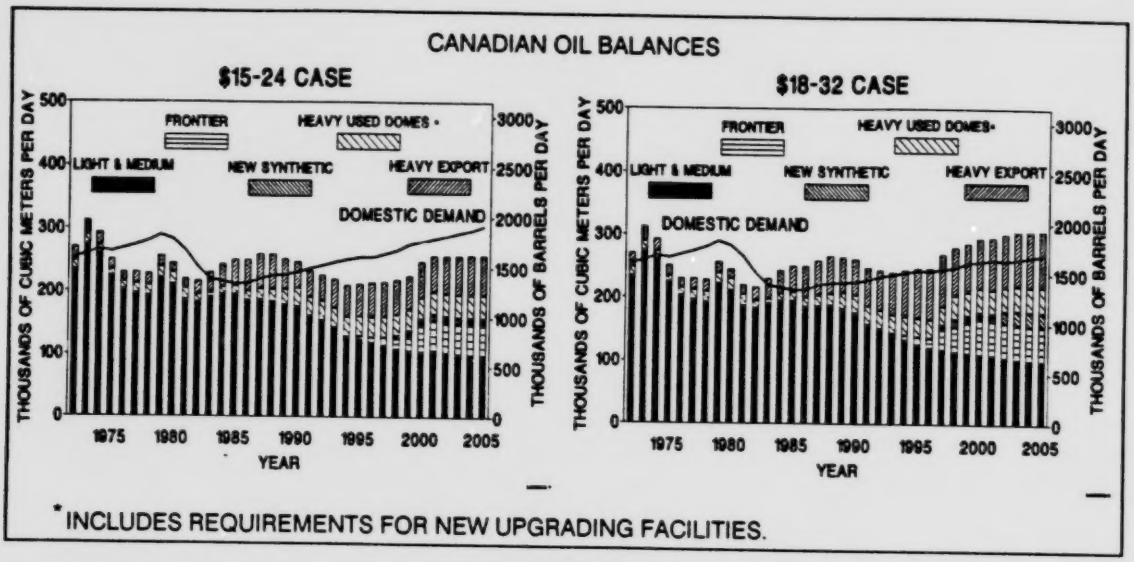

CHART 6.3

In both scenarios, however, Canada is expected to remain dependent on relatively large imports of light oil. In other words, the demand for light and medium crude continues to exceed the production of light crude oil, and this difference is expected to grow over the projection period. In the $15-24 scenario, net light crude oil imports are projected to grow from 105 Mb/d in 1987 to 637 Mb/d in 2005 accounting for 33 per cent of total domestic oil demand. In the $18-32 scenario, light oil imports are projected to increase at a slower rate to 320 Mb/d in 2005 accounting for a relatively smaller, 18 per cent share of demand.

Oil and Gas Upstream Investment

In the $15-24 scenario, oil and gas investment is projected to decline further in the next few years from $5.6 billion (1987 dollars) in 1987 (Table 6.5). After 1990, it is

Table 6.5

Oil and Gas Upstream Investment*
(billions of 1987 dollars)

	$15-24	$18-32
1986	6.7	6.7
1987	5.6	5.6
1990	4.2	6.4
1995	7.2	9.9
2005	9.5	13.2

* Includes government incentives of $840 million (PIP) in 1986 and $330 million (PIP and CEDIP) in 1987.

projected to recover and increase steadily to attain $9.5 billion by 2005.

In the $18-32 scenario, oil and gas investment is projected to remain relatively stable in the next few years at about $6 billion. As prices increase rapidly in the 1990s, oil and gas investment is projected to increase to $13 billion by 2005.

In the development of the oil and gas investment outlook, it is assumed that, in the long run, about 70 per cent of industry internal cash flow is re-invested. In the short run, however, the re-investment ratio for the $15-24 scenario is 95 per cent, much higher than the 85 per cent projected for the $18-32 scenario. As well, these levels could rise if there were substantial net injections of investment capital into the petroleum sector from outside the industry.

Conclusions

Under both price scenarios, crude oil supply is projected to decline until the mid-1990's before rebounding over the balance of the projection period. Oil supply in the $15-24 scenario rises back to its 1987 level of about 1.6 Mb/d and it reaches 1.9 Mb/d in 2005 in the $18-32 scenario. The share of conventional light oil production of total supply falls from about two thirds in 1987 to around one third in 2005. In the lower price scenario, assumed development of non-conventional supplies is delayed or reduced in the case of virtually all major projects.

Blended heavy crude oil supply is projected to increase rapidly by 185 Mb/d and 355 Mb/d in the $15-24 and $18-32 scenarios respectively. Market potential for heavy crude oil is expected to exceed supply throughout the projection period.

In the $18-32 scenario, Canada is expected to remain a net oil exporter, while in the $15-24 scenario net imports are projected to attain about 13 per cent of total domestic demand by 2005. In both scenarios, however, Canada is a growing net importer of light and medium crude oil. Net light oil imports are projected to rise from less than 10 per cent of total oil demand in 1987 to 18 per cent in the $18-32 scenario and to 33 per cent in the $15-24 scenario.

7. Natural Gas Supply Capability and Export Potential

Introduction

The outlook for natural gas supply and exports is discussed below, with some comparisons to the 1986 outlook of the National Energy Board (NEB). The gas export forecast was developed by discussions within the Department, while reflecting views of a number of external studies.

Current Situation

Natural gas production is currently constrained by gas demand, not production capacity. Marketable natural gas production peaked in 1985 at 2.73 Tcf, a level slightly higher than the previous peak level in 1979. One of the reasons for this peak was that exports of 923 Bcf were at their highest level since 1979. In 1986, both domestic demand and exports fell as gas prices failed to adjust quickly to the much lower oil prices. In addition to the lower oil prices, exporters also had to contend with regulatory problems in the United States and increasingly obstructive activities by U.S. producers trying to protect their own market share. In the past two decades, Canadian gas natural exports have barely exceeded 1.0 Tcf in four years: 1972, 1973, 1977 and 1979.

Preliminary data for 1987 indicate that domestic demand is down by about one per cent, but that exports rebounded from 745 Bcf in 1986 to about 990 Bcf in 1987. One reason for the increase in exports was related to exceptionally dry weather in California, which increased natural gas demand for electricity generation. That development more than offset the declining demand from other areas as a result of an abnormally warm winter. Another reason for the increased exports was that deregulation of the Canadian markets has allowed producers to compete move effectively on price, to gain entry into new U.S. markets and to protect existing markets.

Supply Capability

The forecasts of Canadian capability to supply natural gas vary widely. That of the NEB, produced in September 1986, indicated declining productive capacity after the late 1980s (see Chart 7.1). Those projections are based on the belief that the reserves additions in the 1976-1982 period, which were the result of very high oil prices and high drilling rates, are unlikely to be repeated. Under this scenario, the low reserves additions in the face of increasing demand will force frontier production within 10 to 15 years. This result is shown by the NEB supply/demand graphs below. If exports to the United States were to increase to 1.3-1.5 Tcf per year, and be sustained at those levels, the NEB forecast would result in a deliverability problem by the mid-1990s. Alternative analyses at EMR generally support a more favourable view of conventional (non-frontier) gas supply. It is assumed in those analyses that future gas drilling will represent only about 35 per cent total drilling.

Such a development would further support the EMR projections of greater gas producibility. With the oil price forecasts and gas export projections used in this report, no problems are anticipated in the

deliverability of natural gas (see Chart 7.2) Under the high-price scenario, a substantial excess capacity is projected to continue over the entire forecast period. This excess capacity refers only to conventional, western basin gas. If the frontiers, such as the Mackenzie Delta, were to be developed for the export market, then the supply capability could be even higher.

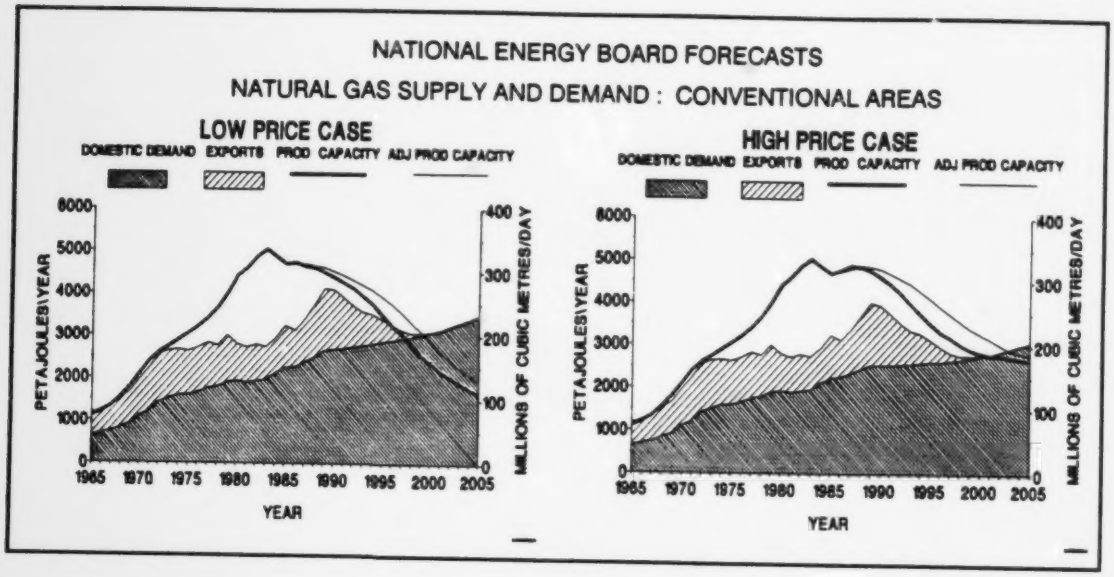

CHART 7.1

Trade in Natural Gas

As mentioned above, Canadian gas exports have reached 1.0 Tcf in only four years in the past two decades. When oil prices have increased sharply, U.S. drilling has increased and, in the case of gas but not oil, a surplus has been generated. The recent "gas bubble" in the United States has been generated to a considerable degree by the very sharp fall in U.S. gas demand from 23 Tcf in 1972 to only 17 Tcf in 1986. The 6 Tcf drop in annual U.S. demand is equivalent to two times the yearly annual production of Canada.

These events have meant that Canadian exports of natural gas are currently constrained by weak markets and competition from surplus producibility in the United States. It is expected that these constraints will disappear over the forecast period as US supply falls, providing significant opportunities for new volumes of exports from Canada at higher prices than currently prevail. Physical constraints in terms of transmission facilities will become more important factors in determining export volumes.

These considerations are reflected in the forecast. Exports are projected to remain in the 1-1.2 Tcf range for the next few years. Thereafter, exports are projected to increase to the 1.3-1.5 Tcf range, reflecting the limitations of existing facilities. There is estimated to be considerable additional market potential for

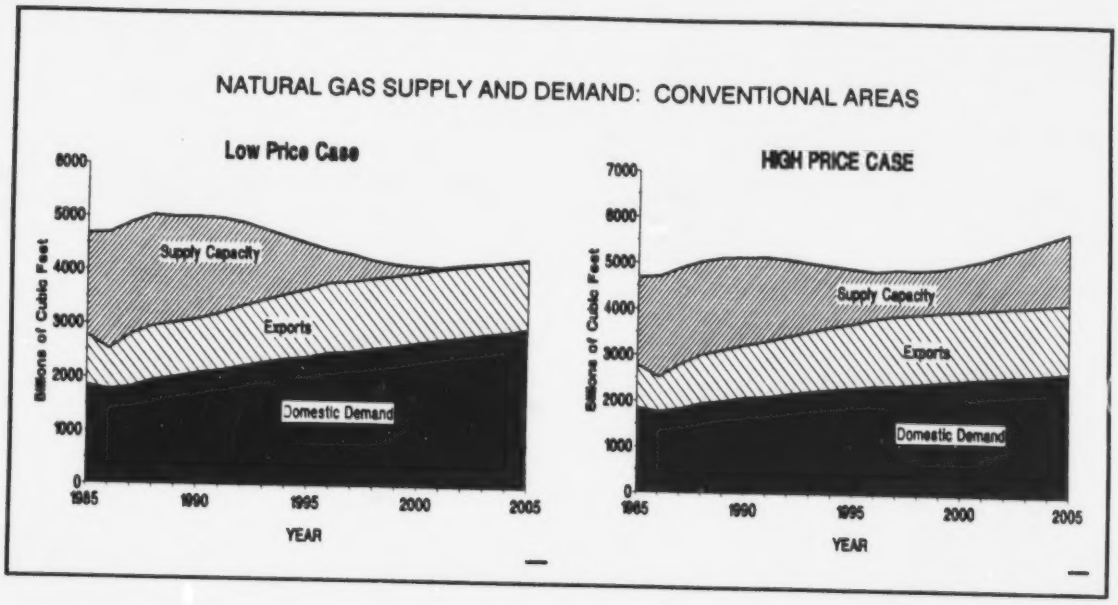

CHART 7.2

Canadian gas if facilities can be put in place to accommodate higher volumes within the projection period. This forecast is intended to provide a conservative estimate of gas export prospects, which new developments, based on freer trading relationships and the strong Canadian resource base (including northern frontier gas), could significantly improve.

The higher exports projected in the higher oil price case reflect fuller use of existing facilities as stronger US gas demand enables Canadian exporters to contract for more constant flows, less subject to seasonal demand fluctuations.

Conclusions

Gas exports are projected to remain around 1 Tcf for the next few years before climbing towards 1.3-1.5 Tcf. In our projections, natural gas supply is expected to accommodate these exports without difficulty, suggesting that there may be potential to exceed this export performance. Significantly higher exports than the forecast levels are possible if new facilities are forthcoming.

8. Electricity Capacity and Generation

Introduction

In the case of electricity, supply for the most part responds to expectations regarding demand. Changes in electricity supply and associated investment lead, however, to electricity price changes which in turn affect electricity and other fuel demands. Because of the relationship between supply, price and demand, an integrated electricity supply and demand modelling framework was used to obtain consistent electricity price, supply and demand projections. These require the convergence of the results from the electricity supply model, UGENEX, with those of the energy demand model, IFSD. Electricity demand from the IFSD is used as input by UGENEX to generate electricity capacity and investments. These are, in turn, used by IFSD to project new prices and energy demands.

Available information on utilities' profiles of future capacity additions has been incorporated into UGENEX. Committed capacity is added in the year indicated by the utility, but uncommitted capacity is added when there is sufficient demand to warrant its installation. Electricity prices in IFSD are estimated on the basis of utilities' financial targets such as revenue requirements, capital and operating costs and expected sales revenues.

Current Situation

The electric power industry currently has a large amount of excess capacity in most regions of Canada. This has resulted from recent capacity additions in anticipation of continued high growth rates of demand such as those experienced during the 1960s and early 1970s. Since the 1970s, Canadian electricity exports to the United States have been accounting for an increasing share of electricity generation and energy export earnings. These increases come mainly from the current surpluses. Export growth was, however, temporarily interrupted in 1986 mainly as the result of the collapse of world oil prices and regulatory problems in accessing the California market.

Although types of electric power generation vary from one province to another reflecting different economics and available resources, hydro continues to be the major source of generation in Canada. Coal and nuclear, however, have been accounting for a larger portion of electrical capacity and generation. Electricity generated by oil and gas accounts for a very small and shrinking share of total electricity generated in Canada.

Installed Generating Capacity

Generating capacity over the projection period to 2005 is expected to increase at an average annual rate of 2.2 per cent under both the $15-24 and $18-32 scenarios (Table 8.I). Because of the current surplus, generation capacity is projected to increase over the period 1986 to 1990 at an average annual rate of only 1.4 to 1.6 per cent. Of the principal types of capacity, nuclear is projected to increase the fastest to 1995.

At the end of the projection period, the shares of capacity by major fuel types are very similar to the shares in 1986. In the short run, the nuclear share increases from 11 per cent in 1986 to 13 per cent in the early 1990s, as the Darlington station in Ontario is completed. The nuclear share declines after 1995 as no new nuclear facilities are expected to be completed before the early 2000s. Given the long lead time for new

nuclear capacity of about 14 years, the earliest possible completion date for new nuclear stations in Ontario is 2002.

Almost all additional capacity is installed by utilities with industries accounting for only 1 GW out of a total increase of about 52 GW in capacity.

Table 8.1

Total Installed Generating Capacity
(GW)

	Hydro	Nuclear	Coal	Other	Total
$15-24					
1986	57.3	11.0	16.0	15.2	99.5
	(58.)	(11.)	(16.)	(15.)	
1990	59.5	13.6	17.2	15.9	106.2
	(56.)	(13.)	(16.)	(15.)	
1995	67.2	15.4	19.7	18.1	120.4
	(56.)	(13.)	(16.)	(15.)	
2000	78.2	15.4	22.1	19.1	134.8
	(58.)	(11.)	(16.)	(14.)	
2005	87.9	17.6	24.1	21.0	150.6
	(58.)	(12.)	(16.)	(14.)	
$18-32					
1986	57.3	11.0	16.0	15.2	99.5
	(58.)	(11.)	(16.)	(15.)	
1990	58.5	13.6	17.2	16.0	105.3
	(56.)	(13.)	(16.)	(15.)	
1995	67.2	15.4	19.7	18.3	120.6
	(56.)	(13.)	(16.)	(15.)	
2000	77.4	15.4	22.8	19.6	135.2
	(57.)	(12.)	(17.)	(14.)	
2005	87.0	16.9	26.1	21.6	151.6
	(58.)	(11.)	(17.)	(14.)	

Note: The numbers in parentheses are percentage shares.

Electricity Generation

Electricity generation over the projection period to 2005 is expected to increase at an average rate of about 2.6 per cent under both the $15-24 and $18-32 scenarios (Table 8.2). These rates are slightly higher than the growth of installed capacity. As a result of current excess capacity, the growth in installed capacity in the next few years is slower than generation growth.

As in the case of capacity, the share of nuclear generation increases in the short term and decreases in the long term to the 1986 level. From 15 per cent in 1986, it reaches 19 per cent in 1990 and drops back to 15 per cent in 2005 under the $18-32 scenario. Hydro and nuclear, which in 1986 accounted for 82 per cent of total generation in Canada, are expected to maintain their dominance over the projection period. The

Table 8.2

Total Electricity Generation

(Twh)

	Hydro	Nuclear	Coal	Other	Total
$15-24					
1986	308.	68.	67.	13.	456.
	(67.)	(15.)	(15.)	(3.)	
1990	329.	95.	64.	20.	508.
	(65.)	(19.)	(12.)	(4.)	
1995	368.	108.	96.	22.	594.
	(62.)	(18.)	(16.)	(4.)	
2000	416.	108.	115.	38.	677.
	(61.)	(16.)	(17.)	(6.)	
2005	466.	118.	126.	40.	750.
	(62.)	(16.)	(17.)	(5.)	
$18-32					
1986	308.	68.	67.	13.	456.
	(67.)	(15.)	(15.)	(3.)	
1990	330.	95.	64.	21.	509.
	(65.)	(19.)	(12.)	(4.)	
1995	364.	108.	98.	23.	593.
	(61.)	(18.)	(17.)	(4.)	
2000	410.	108.	117.	39.	674.
	(61.)	(16.)	(17.)	(6.)	
2005	456.	113.	135.	41.	745.
	(61.)	(15.)	(18.)	(6.)	

Note: The numbers in parentheses are percentage shares.

share of coal generation is projected to increase slightly in the 1990s as coal plants are used more intensively in Ontario in order to meet the increase in demand and the delay in the installation of new nuclear facilities.

Surplus Capacity

In the next few years, the current surplus will be reduced as a result of less expansion of generation capacity, continued exports and increased domestic demand resulting from positive economic growth and real price reductions. As a result, surplus capacity is projected to decline from 36 per cent in 1986 to about 32 per cent in 1990 and to average approximately 27 per cent, which is the minimum historical surplus, over the remainder of the projection period (Table 8.3 and Chart 8.1).

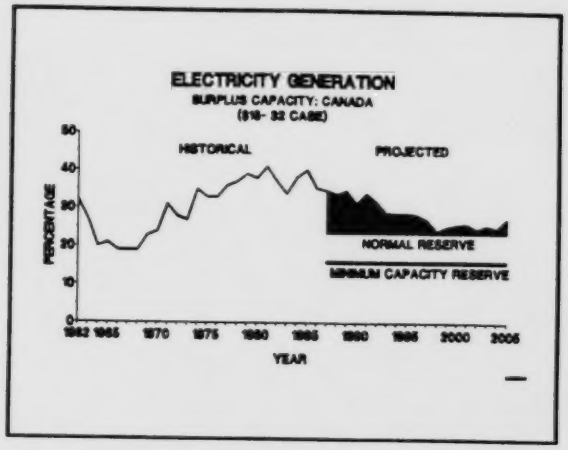

CHART 8.1

Table 8.3

Surplus Generation Capacity in 1986
(%)

	Reserve Margin	Capacity Reserve Requirement	Net Surplus
Newfoundland	27.	12.	15.
Prince Edward Island	58.	15.	43.
Nova Scotia	33.	20.	13.
New Brunswick	64.	17.	47.
Quebec	26	10.	16.
Ontario	43.*	21.	22.
Manitoba	21.	12.	9.
Saskatchewan	32.	11.	21.
Alberta	29	22.	7.
British Columbia	55.	18.	37.
Canada	36.	16.	20.

*Capacity includes mothballed units.

Exports

The evolution of electricity trade over the next 20 years is contingent on the resolution of a number of critical issues. Although a sizeable electricity surplus is expected, factors such as regulatory constraints in the United States and Canada, the availability of transmission capability, contract and technical reliability considerations and the limited scope for coordinated planning between Canadian and American utilities could seriously limit the sale of Canadian electricity to the United States. Moreover, the resolution of these issues would not be sufficient to guarantee growth in electricity exports to the United States.

The U.S. outlook for supply and demand is the overriding consideration in assessing the prospects for electricity trade growth. However, U.S. electricity demand evolution is highly uncertain.

Electricity exports are projected to remain at current levels over the next few years as Canadian utilities sell surplus energy to their U.S. counterparts as they have done in the past. However, markets for export-specific facilities are not expected to be significant because of the perceived uncertainty about the evolution of U.S. demand and the requirement for these facilities to meet future domestic demand growth. Hydro-Québec has, however, made substantial efforts to develop its market in the U.S. and is about to finalize export contracts totalling 2400 MW of firm power with delivery commencing in the mid to late 1990s.

Canadian electricity imports will be maintained at approximately the same level as in the past as utilities on both sides of the border continue to enjoy advantages such as seasonal diversity exchanges.

Conclusions

Electricity generation is projected to increase at an average annual rate of 2.6 per cent over the projection period under both scenarios. Due to the existence of current surpluses, generating capacity is projected to expand at a slower average rate (2.2 per cent) and still meet capacity reserve requirements in the various regions of Canada.

The shares of capacity by different fuel types do not differ significantly in 1986 and 2005, although the nuclear share expands and then contracts.

9. Coal Production and Trade

Introduction

Coal demand projections are developed with the aid of the IFSD system. Coal production estimates are then derived on the basis of domestic demand and export projections. Estimates of coal exports and imports are obtained based on information provided by the EMR Coal Division.

Coal Production

Canada has substantial discovered coal resources. According to the latest Geological Survey of Canada estimates, the portion of these resources classified as recoverable reserves is estimated to be 6578 megatonnes, more than 100 times Canada's current annual production. Of these reserves, over 93 per cent are located in the western provinces of Saskatchewan (25 per cent), Alberta (29 per cent) and British Columbia (39 per cent).

Canada's coal production is determined principally by demand in two major markets: the electricity generation industry's use of domestic thermal coal and international, largely Japanese, requirements for metallurgical (coking) coal. Together, these two markets consumed 90 per cent of domestic coal production in 1986. Total exports including thermal coal accounted for 45 per cent of Canadian production.

Because of transportation costs, domestic demand for metallurgical coal usually is met by imports from the U.S. while virtually all domestic metallurgical coal production is sold on the export market. In 1986, imports of metallurgical coal from the U.S. accounted for 95 per cent of domestic consumption. In the domestic market, the electrical generation industry is by far the largest consumer of coal. It accounted for 82 per cent of total domestic coal consumption in 1986.

Table 9.1 shows that coal production is projected to increase steadily over time. Production under both scenarios is projected to increase at an average annual rate of 3.4 per cent from 1986 to 2005. There are, however, uncertainties with regard to both domestic demand and export prospects.

The principal areas of uncertainty with regard to domestic demand for coal are Ontario Hydro's generation expansion plans after 1992, environmental concerns and the legislation of emission standards. Ontario's coal requirements for electricity generation are expected to decline in the next few years as new nuclear capacity now under construction comes into service and replaces existing thermal plants. Ontario Hydro has not, however, publicly announced its expansion plans beyond the completion of the Darlington nuclear station in 1992.

On the basis of projected electricity demand in Ontario, additional generation capacity will be required before 2000, but it is already too late to bring on new nuclear capacity before 2002 because of the long lead time required for construction of nuclear plants. In the coal demand projection in Table 8.1, it is assumed that a large share of the growth in electricity demand in the mid- to late 1990s is met by the more intensive use of existing coal-fired thermal plants and the rehabilitation of retired coal plants, which will have to be retrofitted with improved emission control equipment. The use of coal-fired thermal generation could, however, be limited if growing concerns over acid rain lead to the adoption of much stricter sulphur dioxide emission standards.

Coal Exports

The coal market worldwide, including Canada, has experienced large capacity increases in recent years. This combined with the stabilization in the world demand for metallurgical coal has resulted in excess

Table 9.1

Coal Supply, Demand and Trade
(Megatonnes)

	Production	Domestic Demand	Exports	Imports	Net Exports
$15-24					
1986	57.	45.	26.	13.	13.
1990	63.	45.	28.	10.	18.
1995	84.	62.	32.	10.	22.
2000	97.	74.	35.	12.	23.
2005	107.	82.	39.	14.	25.
$18-32					
1986	57.	45.	26.	13.	13.
1990	63.	45.	28.	10.	18.
1995	86.	64.	32.	10.	22.
2000	96.	73.	35.	12.	23.
2005	108.	83.	39.	14.	25.

production capacity, and has led to intense competition among coal exporters for markets. Canadian exporters are also faced with relatively expensive long rail hauls to tidewater and an appreciating Canadian dollar in the last few years. These events have severely eroded new export opportunities for Canadian metallurgical coal. These conditions also prevail in the case of steam coal. Nevertheless, future growth in international steam coal demand is expected to represent selected market opportunities for Canadian exporters.

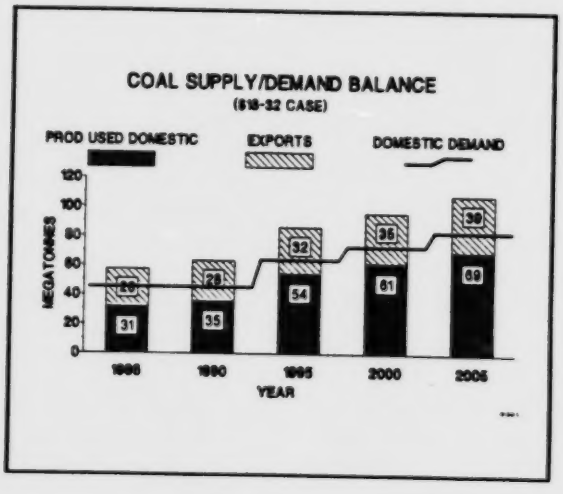

CHART 9.1

In both oil price scenarios, coal exports are projected to increase at a modest average annual growth rate of 2.2 per cent to reach 39 megatonnes by 2005. By comparison, coal exports have grown at a much faster average annual rate of 8.1 per cent in the last 10 years.

Conclusions

The outlook for demand for Canadian coal hinges on a number of critical factors. They include Ontario Hydro's generation expansion plans after 1992, environmental concerns and the legislation of emission standards and the international competitiveness of Canadian coal. In spite of these uncertainties, coal production is projected to increase at an average annual rate of 3.4 per cent (see Chart 9.1).

Appendix A: Summary Tables for the $18-32 Scenario

A.1 Macroeconomic Assumptions

A.2 World and Domestic Crude Oil Prices

A.3 Domestic and Export Natural Gas Prices

A.4 Electricity Price Determination

A.5 Comparative Fuel Prices by Sector

A.6 Supply and Demand for Petroleum

A.7 Supply and Demand for Natural Gas and LPGs

A.8 Electricity Supply and Demand

A.9 Summary Results - Energy Demand

TABLE A.1: MACROECONOMIC ASSUMPTIONS REGION: CANADA

		FORECAST 1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	OUTPUT AND INCOME: (1981=100.0) (CONSTANT 81$)										
GNIK	REAL GNE	108.33	111.57	114.92	118.60	120.97	123.39	125.86	136.23	150.41	166.07
RDIC	RDP - TOTAL	106.97	110.73	114.03	117.69	120.68	123.09	125.55	135.90	150.05	165.66
RDIAGC	- AGRICULTURE	101.11	109.01	106.80	106.54	112.55	115.17	117.85	129.23	145.00	162.70
RDIINC	- INDUSTRIAL	103.62	105.06	106.43	111.98	115.57	117.88	120.24	130.15	143.69	158.65
RDIIRC	- IRON & STEEL (NAT'L)	103.28	100.80	102.61	108.57	112.26	115.18	118.17	130.95	148.88	169.27
RDICIC	- COMMERCIAL & PUBLIC ADMIN	110.06	116.43	123.04	126.13	128.86	131.56	134.32	145.97	161.95	179.69
RDIAVC	- AVIATION (NAT'L)	110.71	112.07	103.01	109.36	113.53	116.71	119.98	133.99	153.83	176.60
RDIRLC	- RAIL (NAT'L)	101.47	100.50	98.57	101.97	104.49	107.10	109.77	121.17	137.09	155.11
RDIICC	RDP PER CAPITA	102.66	105.24	107.31	109.70	111.42	112.62	113.93	119.69	128.13	138.09
YIDKC	REAL PERSONAL DISPOSABLE INCOME	105.56	106.83	108.43	110.27	112.70	114.16	115.65	121.78	129.91	138.57
YIDICC	PERS'L DISP. INCOME PER CAPITA	101.30	101.53	102.05	102.78	104.06	104.45	104.95	107.26	110.93	115.51
	PRICES AND COSTS: (1981=1.0)										
PWPIUS	U.S. WPI (1967=100.0)	308.7	297.6	304.4	313.3	327.4	342.1	357.5	426.3	531.3	662.0
PGDP	GDP DEFLATOR - TOTAL	1.250	1.266	1.321	1.373	1.442	1.511	1.583	1.910	2.415	3.052
PGDPAG	- AGRICULTURAL	0.953	0.936	0.911	0.932	0.956	0.988	1.022	1.168	1.381	1.632
PGDPIN	- INDUSTRIAL	1.262	1.326	1.392	1.424	1.471	1.539	1.609	1.927	2.412	3.021
PGDPCP	- COMMERCIAL	1.271	1.345	1.434	1.517	1.603	1.684	1.768	2.149	2.742	3.500
PCXDE	PERS. CONS. DEFLATOR EX. ENERGY	1.262	1.322	1.383	1.448	1.513	1.581	1.653	1.973	2.461	3.069
CPI	CONSUMER PRICE INDEX	1.271	1.325	1.379	1.447	1.532	1.609	1.689	2.053	2.621	3.345
PFX	EXCHANGE RATE ($CDN/$US)	1.366	1.390	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330
RIPRVB	AVG. YIELD - 10 PROV'L BONDS	11.7	9.5	9.8	10.1	10.4	10.0	10.0	10.0	10.0	10.0
	DEMOGRAPHIC: ('000)										
POPC	TOTAL POPULATION	25352.	25598.	25852.	26102.	26350.	26593.	26811.	27624.	28491.	29188.
HHC	TOTAL HOUSEHOLDS	9079.	9334.	9513.	9686.	9851.	10011.	10159.	10717.	11362.	11964.
RHHSTC	SINGLE / MULTIPLE HOUSEHOLDS	0.652	0.668	0.667	0.667	0.667	0.666	0.666	0.665	0.666	0.667
	LABOUR FORCE: ('000)										
POPLFC	LABOUR FORCE SOURCE POPULATION	19372.	19602.	19851.	20091.	20324.	20552.	20760.	21556.	22474.	23288.
LFC	LABOUR FORCE	12639.	12877.	13114.	13282.	13449.	13581.	13749.	14326.	14871.	15291.
EMPC	TOTAL EMPLOYMENT	11311.	11635.	11900.	12093.	12289.	12424.	12548.	12967.	13495.	14043.
URATEC	UNEMPLOYMENT RATE (%)	10.51	9.65	9.26	8.95	8.63	8.52	8.74	9.48	9.26	8.16
	PASSENGER VEHICLES:										
NPVSTC	SALES - VOLUME ('000)	1137.2	1059.1	1029.8	1070.0	1092.7	1142.5	1179.4	1280.3	1333.6	1418.5
ENPVS	- EFFICIENCY (L/100KM)	10.6	10.6	10.7	10.6	10.5	10.4	10.6	10.1	9.4	9.2
KTPVSC	STOCK - VOLUME ('000)	9576.5	9713.4	9815.5	9956.7	10122.3	10334.0	10573.3	11622.8	12781.9	13672.6
EKTPVC	- EFFICIENCY (L/100KM)	12.3	12.3	12.0	11.7	11.4	11.2	11.0	10.6	10.0	9.5
KTMAC	MANUFAC'NG CAPITAL STOCK ($81B)	118.947	122.337	125.835	129.434	133.162	136.504	139.303	152.745	168.179	191.218
KGDSC	NATURAL GAS DIST. CAPACITY (MCM)	830.	841.	849.	853.	856.	862.	868.	889.	913.	931.
DDAYSC	HEATING DEGREE DAYS (NORM=1)	1.013	0.962	0.926	1.000	1.000	1.000	1.000	1.000	1.000	1.000

TABLE A.2: WORLD AND DOMESTIC CRUDE OIL PRICES
($/CUBIC METRE)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	WEST TEXAS INTERMEDIATE: ($US)										
PWTCU	CUSHING	176.20	94.77	121.33	119.28	124.65	130.26	145.19	225.45	337.14	448.15
PWTCUR	REAL ($1986)	171.52	94.77	118.37	113.27	113.27	113.27	120.82	157.32	188.79	201.37
TOCUCH	TRANSPORTATION TO CHICAGO	2.83	2.32	2.84	2.88	2.95	3.02	3.08	3.37	3.77	4.21
TRFDU	U.S. REFINERY TAX	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
PWTCH	CHICAGO	179.53	97.59	124.67	122.67	128.10	133.78	148.78	229.32	341.41	452.86
	BRENT ($US)										
PBRNS	NORTH SEA (F.O.B)	173.95	91.54	117.65	114.95	120.25	125.75	140.46	219.55	329.62	438.98
TOLOSS	OCEAN LOSS	0.70	0.37	0.47	0.46	0.48	0.50	0.56	0.88	1.32	1.76
TONSPO	TRANSPORTATION TO PORTLAND	5.51	5.12	4.63	4.70	4.81	4.91	5.03	5.49	6.14	6.86
TOPOMO	TRANSPORTATION TO MONTREAL	5.30	3.97	4.14	4.20	4.29	4.39	4.49	4.90	5.48	6.13
PBRMO	MONTREAL (C.I.F)	185.46	101.00	126.89	124.30	129.83	135.55	150.53	230.82	342.55	453.72
	LANDED IMPORT COST:										
PCRICA	IMPORT MIX ADJUSTMENT	-5.35	2.41	-7.93	-8.70	-9.09	-9.49	-10.54	-16.16	-23.98	-31.76
PCRMU	AT MONTREAL (CIF) ($US)	180.11	103.41	118.96	115.60	120.74	126.07	139.99	214.66	318.58	421.96
PFX	EXCHANGE RATE ($CDN/$US)	1.366	1.390	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330
PCRMT	AT MONTREAL (CIF) ($CDN)	250.33	143.74	158.22	153.75	160.59	167.67	186.19	235.50	423.71	561.21
	CANADIAN PAR:										
PPACH	CHICAGO ($US)	183.08	98.95	123.55	122.67	128.10	133.78	148.78	229.32	341.41	452.86
TRFPAU	U.S. IMPORT TARIFFS	0.66	0.83	1.60	1.64	1.61	1.62	1.64	1.78	1.97	2.16
TOBOCH	TRANSPORTATION TO U.S. BORDER	3.06	2.97	2.97	3.01	3.08	3.15	3.22	3.52	3.94	4.40
TOBOED	TRANSPORTATION TO EDMONTON	1.60	1.77	2.27	2.31	2.37	2.43	2.49	2.74	3.08	3.47
PPAED	EDMONTON ($CDN)	242.82	129.80	155.22	153.87	160.98	168.35	188.10	294.31	442.13	588.98
	REFINERY CRUDE COST ($CDN):										
PCRATA	ALBERTA	234.98	124.48	149.64	148.49	155.35	162.46	181.52	284.02	426.66	568.37
PCRATO	ONTARIO	242.14	132.12	156.45	155.66	160.93	168.15	184.76	285.58	428.46	571.80
PCRATQ	QUEBEC	244.66	133.36	159.33	158.63	163.56	170.84	186.92	287.51	430.63	574.57
PCRATF	ATLANTIC	224.15	140.81	155.65	148.17	154.88	161.83	180.23	278.98	416.42	553.06

TABLE A.3: DOMESTIC AND EXPORT NATURAL GAS PRICES
($/GIGAJOULE)

		FORECAST								
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	DOMESTIC PRICE:										
PNGAB	AVERAGE ALBERTA BORDER.....	2.80	2.66	1.87	1.91	2.06	2.29	2.47	4.68	7.77	10.88
PNGABR	RESIDENTIAL.....	2.80	2.75	2.24	1.99	2.19	2.47	2.47	4.68	7.77	10.88
PNGABC	COMMERCIAL.....	2.80	2.69	2.14	1.99	2.10	2.36	2.47	4.68	7.77	10.88
PNGABI	INDUSTRIAL.....	2.80	2.41	1.68	1.83	1.96	2.15	2.47	4.68	7.77	10.88
PGDSAB	DIRECT SALES.....	2.80	2.30	1.20	1.42	1.83	2.15	2.47	4.68	7.77	10.88
PCMPAB	CMP'S.....	2.80	2.42	1.80	1.97	2.01	2.15	2.47	4.68	7.77	10.88
GOPAR	TORONTO GAS/OIL PARITY.....	0.60	0.99	0.74	0.75	0.77	0.80	0.77	0.81	0.83	0.85
	EXPORT PRICE:										
PNGXT	EXPORT PRICE ($CDN).....	4.09	3.21	2.43	2.67	2.80	2.99	3.05	5.31	8.49	11.69
PFX	EXCHANGE RATE ($CDN/$US).....	1.37	1.39	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33
PNGXU	EXPORT PRICE ($US).....	3.00	2.31	1.83	2.01	2.11	2.25	2.29	4.00	6.38	8.79

TABLE A.4: ELECTRICITY PRICE DETERMINATION (NOMINAL) REGION: CANADA

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	UTILITY FUEL INPUT PRICES: ($/GJ)										
PCCUEC	COAL	1.450	1.371	1.274	1.468	1.566	1.575	1.757	2.312	2.733	3.258
PHFUEC	HEAVY FUEL OIL	5.354	3.307	3.345	3.077	3.214	3.356	3.905	6.043	7.602	9.694
PDSUEC	DISTILLATES	9.419	5.999	7.088	7.028	7.345	7.685	8.348	12.055	17.331	23.286
PNGUEC	NATURAL GAS	2.193	2.307	2.206	1.898	1.864	2.486	3.411	6.170	9.618	13.062
PNUUEC	NUCLEAR	0.385	0.408	0.426	0.443	0.465	0.487	0.511	0.616	0.779	0.984
POFUEC	OTHER FUELS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	PLANNED COSTS: ($MILLIONS)										
FPETTC	TOTAL PLANNED COSTS	16097.0	16883.0	18058.3	18746.5	19641.2	20548.6	21792.5	28271.9	38504.4	55166.5
FPEOCC	PLANNED OPERATING COSTS	6196.4	6133.9	6605.5	6846.0	7176.3	7656.3	8693.3	12360.0	18571.6	25700.6
FPFULC	PLANNED FUEL COSTS	1861.9	1634.0	1735.6	1900.0	1965.6	2141.1	2734.2	4445.2	7463.7	10172.1
FIWSAC	WAGES AND SALARIES	2679.4	2679.4	2877.9	2980.7	3166.3	3316.0	3636.1	4860.3	6873.7	9788.9
FPEOOC	OTHER OPERATING COSTS	624.2	696.9	785.5	782.2	811.0	880.7	926.5	1265.5	1800.3	2484.7
FITXSC	INDIRECT TAXES	679.7	732.6	732.7	748.8	779.0	828.1	872.1	1087.1	1424.5	1840.7
FIROYC	ROYALTIES	351.2	391.0	473.8	434.4	454.4	490.3	524.4	701.8	1009.4	1414.3
FIEFXC	FIXED COSTS	7844.7	8300.7	8913.1	9320.6	9621.0	10009.6	10224.8	12285.9	15686.1	22136.3
FIINTC	NET INTEREST COSTS	5952.8	6277.1	6728.5	7056.3	7233.6	7558.8	7610.8	9087.5	11569.0	16363.8
FIDEPC	DEPRECIATION	1891.9	2023.5	2184.6	2264.2	2387.4	2450.8	2614.1	3198.4	4117.1	5772.5
FIRETC	TOTAL RETURN ON NET EQUITY	1048.9	1496.0	1656.4	1742.5	2050.2	2166.4	2202.3	2813.2	3366.8	6360.4
FICRPC	PLANNED CONTRIB'N TO RESERVE	18.8	0.0	-8.4	-16.9	-34.9	-99.8	-137.7	-20.8	-70.3	-173.7
FPFEXC	PLANNED EXCHANGE LOSS	548.8	464.3	379.3	330.0	287.1	249.8	217.3	124.5	62.1	30.9
FIITXC	INCOME TAX	284.8	302.9	317.9	325.3	335.9	351.4	367.5	440.0	550.9	689.8
FIEOXC	OTHER EXPENSES	154.4	185.3	194.5	199.1	205.6	215.0	224.9	269.2	337.1	422.1
	OTHER REVENUE FLOWS: ($MILLION)										
FISAXC	FROM NET EXTERNAL SALES	1389.7	1061.7	1481.7	1196.2	1063.4	1115.7	1130.5	2329.2	3259.0	4130.6
FMRESC	EXTERNAL SALES	2055.8	1061.7	1741.7	1441.5	1251.8	1302.4	1288.9	2522.1	4958.9	6927.0
FMCEPC	EXTERNAL PURCHASES	406.5	0.0	260.0	245.2	188.4	186.7	158.4	192.8	1699.9	2796.4
FISUBC	SUBSIDIES	26.1	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
FIROTC	OTHER OPERATING REVENUE	88.9	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4
FIOTIC	OTHER INCOME	839.8	666.2	699.2	715.6	739.0	773.0	808.5	967.9	1212.0	1517.6
FMRRQC	PLANNED DOMESTIC REVENUE REQUIREMENTS ($MILLIONS)	13752.8	14701.8	15424.0	16381.3	17385.4	18206.6	19400.1	24521.5	33580.1	49065.0
VEUIPC	PLANNED INTERNAL SALES (GHW)	334576.	350762.	364116.	374881.	386167.	399433.	406362.	457957.	520028.	577852.
	AVERAGE PRICES: (CENTS/KWH)										
PELCAC	BASED ON REVENUE REQUIREMENTS	4.111	4.275	4.327	4.443	4.547	4.591	4.838	5.454	6.519	8.383
PELAAC	ANNOUNCED PRICES	4.111	4.563	4.420	4.487	4.522	4.691	4.756	5.292	6.342	7.850
PELFAC	FORECAST PRICES	4.111	4.275	4.408	4.515	4.691	4.747	4.886	5.422	6.561	8.318

TABLE A.5: ENERGY PRICES - THERMAL UNITS ($/GIGAJOULE) REGION: CANADA

		1985	FORECAST 1986	1987	1988	1989	1990	1991	1995	2000	2005
	ENERGY PRICE INDEXES (1981=1.0)										
PDIRAC	RESIDENTIAL	1.41	1.40	1.41	1.42	1.47	1.52	1.58	1.98	2.61	3.44
PDICPC	COMMERCIAL	1.43	1.44	1.47	1.47	1.52	1.56	1.62	1.99	2.62	3.47
PDIINC	INDUSTRIAL	1.38	1.35	1.36	1.35	1.41	1.46	1.54	1.97	2.61	3.41
PDITRC	TRANSPORTATION	1.43	1.28	1.31	1.35	1.40	1.45	1.54	2.04	2.76	3.52
PDISDC	TOTAL SECONDARY DEMAND	1.41	1.35	1.37	1.39	1.44	1.49	1.56	1.99	2.65	3.46
	REGIONAL SECTORAL PRICES: ($/GJ - EFFICIENCY ADJUSTED)										
PULFRC	LFO - RESIDENTIAL	15.25	12.35	11.41	11.56	12.09	12.66	13.66	19.17	26.94	35.48
PULFCC	- COMMERCIAL	12.12	9.92	9.14	9.21	9.61	10.04	10.81	15.11	21.49	28.35
PUHFIC	HFO - INDUSTRIAL	5.72	3.47	3.61	3.50	3.67	3.85	4.28	6.91	10.67	14.37
PUHFCC	- COMMERCIAL	6.32	3.81	3.87	3.83	4.04	4.23	4.71	7.61	11.67	15.73
PUNGRC	NATURAL GAS - RESIDENTIAL	7.55	7.61	7.59	7.52	7.53	8.13	8.31	12.57	18.68	25.14
PUNGCC	- COMMERCIAL	5.54	5.55	5.43	5.09	5.05	5.47	5.72	9.04	13.76	18.62
PUNGIC	- INDUSTRIAL	4.45	4.29	3.97	3.63	3.78	4.08	4.52	7.34	11.31	15.39
PUELRC	ELECTRICITY - RESIDENTIAL	12.08	12.53	13.02	13.28	13.84	14.02	14.46	16.04	19.38	25.27
PUELCC	- COMMERCIAL	15.28	15.84	16.46	16.85	17.51	17.71	18.26	20.19	24.46	32.08
PUELIC	- INDUSTRIAL	8.73	9.08	9.41	9.58	10.00	10.15	10.52	11.92	14.36	18.33
	PRICE RATIOS: (EFFICIENCY ADJ'D)										
	RESIDENTIAL:										
RPEORC	ELECTRICITY / LIGHT FUEL OIL	0.79	1.01	1.14	1.15	1.14	1.11	1.06	0.84	0.72	0.71
RPEGRC	ELECTRICITY / NATURAL GAS	1.60	1.65	1.72	1.77	1.84	1.72	1.74	1.28	1.04	1.00
RPOGRC	LIGHT FUEL OIL / NATURAL GAS	2.02	1.62	1.50	1.54	1.61	1.56	1.64	1.53	1.44	1.41
	COMMERCIAL:										
RPEOCC	ELECTRICITY / LIGHT FUEL OIL	1.26	1.60	1.80	1.83	1.82	1.76	1.69	1.34	1.14	1.13
RPEGCC	ELECTRICITY / NATURAL GAS	2.76	2.86	3.03	3.31	3.47	3.24	3.19	2.23	1.78	1.72
RPOGCC	LIGHT FUEL OIL / NATURAL GAS	2.19	1.79	1.68	1.81	1.90	1.83	1.89	1.67	1.56	1.52
	INDUSTRIAL:										
RPEOIC	ELECTRICITY / HEAVY FUEL OIL	1.53	2.62	2.61	2.74	2.72	2.64	2.46	1.73	1.35	1.28
RPEGIC	ELECTRICITY / NATURAL GAS	1.96	2.12	2.37	2.64	2.64	2.49	2.33	1.62	1.27	1.19
RPOGIC	HEAVY FUEL OIL / NATURAL GAS	1.29	0.81	0.91	0.96	0.97	0.94	0.95	0.94	0.94	0.93

TABLE A.6: SUPPLY AND DEMAND - PETROLEUM
(THOUSANDS OF CUBIC METRES PER DAY)

		FORECAST								
	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	DOMESTIC CRUDE OIL PRODUCTION:									
VCRPN	TOTAL	249.9	250.1	259.1	266.3	264.7	261.8	248.5	247.2	295.4	306.5
QCROO	- CONVENTIONAL OLD OIL	106.3	87.5	77.6	69.7	59.6	52.5	46.1	26.2	12.6	5.5
QSOPN	- SYNTHETIC OIL	26.7	29.3	28.2	28.5	31.0	31.0	31.0	32.6	44.8	56.0
QCRER	- ENHANCED RECOVERY	17.7	20.7	20.4	18.0	15.9	15.3	13.6	14.7	24.0	33.5
QCRNT	- NEW OIL	99.2	112.6	132.9	150.1	158.7	164.0	158.8	174.7	215.0	212.5
QCRUN	- NET HEAVY UPGRADING	0.0	0.0	0.0	0.0	-0.5	-1.0	-1.0	-1.0	-1.0	-1.0
	DOMESTIC CRUDE OIL DEMAND:									
VRPDDC	PETROLEUM PRODUCTS DEMAND	220.5	223.5	231.5	235.1	236.6	237.1	241.4	256.3	271.2	281.6
VCRRG	REFINERY GAIN AND ADJUSTMENTS	9.6	12.6	12.8	12.9	12.9	12.9	13.0	13.3	13.6	13.8
QLPRN	NET REFINERY PROD'N OF LPG'S	1.2	2.1	2.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2
QLPPR	- TOTAL REFINERY LPG PROD'N	6.1	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1
VLPRP	- REFINERY LPG CONSUMPTION	4.9	3.9	4.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9
VCRDD	DOMESTIC CRUDE OIL DEMAND	212.1	213.0	220.7	223.4	224.9	225.4	229.6	244.2	258.8	269.0
	STOCK CHANGE:									
VRPSC	REFINED PETROLEUM PRODUCTS	-5.7	-1.4	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VCRSC	CRUDE OIL	-1.4	-1.0	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PETROLEUM EXPORTS:									
VPEXT	TOTAL	102.8	115.0	121.0	118.3	113.4	107.8	104.9	104.4	102.1	109.1
VCRXT	- CRUDE OIL - TOTAL	77.1	93.0	99.0	96.3	91.4	85.8	82.9	82.4	80.1	87.1
VLMXS	- LIGHT & MEDIUM	32.3	40.7	42.0	35.0	30.0	25.0	18.0	0.0	0.0	0.0
VHVXS	- HEAVY (INCL. DILUENT)	42.5	52.3	57.0	61.3	61.4	60.8	64.9	82.4	80.1	87.1
VCRXE	- EXCHANGES	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VRPXT	- PRODUCTS - TOTAL	25.7	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
	PETROLEUM IMPORTS:									
VPEMT	TOTAL	58.3	75.5	81.6	75.4	73.7	71.4	86.1	101.4	65.5	71.7
VCRMT	- CRUDE OIL	45.0	57.5	63.6	57.4	55.7	53.4	68.1	83.4	47.5	53.7
VRPMT	- PRODUCTS - TOTAL	13.3	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
VPEMN	NET PETROLEUM IMPORTS	-44.5	-39.5	-39.4	-42.9	-39.8	-36.4	-18.8	-3.0	-36.6	-37.4

TABLE A.7: SUPPLY & DEMAND - NATURAL GAS & LPG'S

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	MARKETABLE NATURAL GAS: (MCM)										
VNGPN	TOTAL PRODUCTION	77135.	71893.	77604.	85251.	88189.	91516.	93842.	105244.	113488.	119097.
VNGDD	DOMESTIC DEMAND	52472.	50222.	50020.	55476.	56998.	58908.	59818.	65554.	70965.	76574.
VNGSC	STOCK CHANGE	-1210.	1102.	-84.	400.	400.	400.	400.	400.	400.	400.
VNGXT	EXPORTS - ACTUAL	26153.	21090.	28032.	29745.	31161.	32578.	33994.	39660.	42493.	42493.
VNGMT	IMPORTS	5.	260.	93.	100.	100.	100.	100.	100.	100.	100.
VNGAJ	STATISTICAL ADJUSTMENT	276.	261.	272.	270.	270.	270.	270.	270.	270.	270.
	GAS PLANT LPG'S (KCM/D)										
QLPRN	NET REFINERY PRODUCTION	1.20	2.12	2.00	1.20	1.20	1.20	1.20	1.20	1.20	1.20
VGPPN	GAS PLANT PROD (INCL SOLV FLD	40.43	39.73	43.33	46.78	49.96	52.19	53.17	51.23	47.62	45.52
VPBPN	PROPANE & BUTANE	26.37	25.56	25.63	26.98	27.16	27.39	27.37	26.43	24.82	22.72
QPBRS	FROM REPROCESSING PLANTS	7.50	7.25	8.00	8.00	8.00	8.00	8.00	7.00	7.00	6.00
VETPN	ETHANE	14.06	14.17	17.70	19.80	22.80	24.80	25.80	24.80	22.80	22.80
VGPDD	DOMESTIC DEMAND	21.83	22.83	25.76	25.50	26.61	30.15	32.56	39.17	43.02	46.55
VGPER	REQUIREMENTS FOR EOR PROJECTS	3.50	3.88	4.70	6.00	7.00	8.00	8.00	4.00	2.00	0.00
VGPSC	STOCK CHANGE	-1.18	2.71	2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPAJ	STATISTICAL ADJUSTMENT	-0.25	0.17	-0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPXT	EXPORTS	17.73	12.28	13.10	16.48	17.55	15.24	13.81	9.27	3.80	0.17

TABLE A.8: ELECTRICITY SUPPLY & DEMAND
(GIGAWATT HOURS)

REGION: CANADA

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	GENERATING CAPACITY (MEGAWATTS).										
KEGCTC	TOTAL	94888.	99486.	101484.	102552.	104978.	105260.	109538.	120605.	135149.	151553.
KEGCUC	UTILITIES	88666.	92265.	94249.	95287.	97692.	97861.	102116.	112918.	127330.	143678.
KEGCIC	INDUSTRIES	6222.	7221.	7235.	7265.	7286.	7399.	7422.	7687.	7819.	7875.
	CANGEN PLANNED GENERATION:										
	TOTAL:										
VEUPXC	UTILITIES	409413.	416381.	445293.	444910.	452140.	467366.	480516.	549211.	628533.	698950.
VEIPXC	INDUSTRY	37769.	39450.	40012.	40496.	40849.	41499.	41749.	43342.	45284.	45831.
	FOR DOMESTIC DEMAND:										
VELDXC	TOTAL	406859.	421854.	438394.	451649.	464250.	479259.	490337.	546232.	620008.	690621.
	CANGEN PLANNED CAPACITY FACTOR:										
RGCUPC	UTILITIES	0.527	0.515	0.539	0.533	0.528	0.545	0.537	0.555	0.563	0.555
RGCIPC	INDUSTRY	0.693	0.624	0.631	0.636	0.640	0.640	0.642	0.644	0.661	0.664
	EXTERNAL SALES & PURCHASES:										
VELENC	NET EXTERNAL SALES	40323.	33977.	46911.	33757.	28739.	29606.	31928.	46321.	53809.	54161.
VELXNC	NET EXPORTS TO U.S.	40323.	33977.	46911.	33757.	28739.	29606.	31928.	46321.	53809.	54161.
VELESC	EXTERNAL SALES	43016.	38935.	49925.	35849.	30831.	31698.	34020.	48413.	55901.	56253.
VELXTC	EXPORTS	43016.	38935.	49925.	35849.	30831.	31698.	34020.	48413.	55901.	56253.
VELEPC	EXTERNAL PURCHASES	2693.	4958.	3014.	2092.	2092.	2092.	2092.	2092.	2092.	2092.
VELMTC	IMPORTS	2693.	4958.	3014.	2092.	2092.	2092.	2092.	2092.	2092.	2092.
VELIRC	NET INTER-REGIONAL TRANSFERS	0.	0.	0.	1.	1.	1.	0.	0.	0.	1.
	GENERATION FOR DOMESTIC DEMAND: (INC. OWN-USE)										
VELDDC	TOTAL	406859.	422773.	438143.	451517.	464302.	475909.	489004.	544602.	613893.	678057.
VEUDDC	UTILITIES	369090.	383323.	398131.	411021.	423453.	434410.	447255.	501260.	568609.	632226.
VEIDDC	INDUSTRY	37769.	39450.	40012.	40496.	40849.	41499.	41749.	43342.	45284.	45831.
	TOTAL GENERATION:										
VELPNC	TOTAL	447182.	456750.	485054.	485275.	493042.	505516.	520932.	590923.	667703.	732219.
VEUPNC	UTILITIES	409413.	417300.	445042.	444779.	452193.	464017.	479183.	547581.	622418.	686388.
VEIPNC	INDUSTRY	37769.	39450.	40012.	40496.	40849.	41499.	41749.	43342.	45284.	45831.
	CAPACITY FACTOR:										
RGCUAC	UTILITIES	0.527	0.516	0.539	0.533	0.528	0.541	0.536	0.554	0.558	0.545
RGCIAC	INDUSTRY	0.693	0.624	0.631	0.636	0.640	0.640	0.642	0.644	0.661	0.664

TABLE A.9.1: SUMMARY RESULTS - ENERGY DEMAND REGION: CANADA
(PETAJOULES)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDC	SECONDARY DEMAND BY FUEL:	5996.0	6051.5	6135.1	6357.1	6503.8	6644.4	6792.0	7327.1	7814.3	8320.4
HRPSDC	RPP'S	2389.3	2416.7	2439.8	2505.0	2535.2	2571.0	2602.5	2733.3	2818.9	2953.0
HNGSDC	NATURAL GAS	1547.8	1505.4	1488.9	1568.0	1615.8	1664.7	1716.4	1876.1	1999.9	2113.3
HELSDC	ELECTRICITY	1336.1	1396.6	1447.0	1491.0	1533.2	1571.7	1614.9	1798.7	2027.3	2237.6
HCCSDC	COAL	51.2	49.8	54.0	59.1	62.7	64.1	65.6	67.1	65.8	71.3
HLPSDC	LPG'S	84.9	84.0	91.3	99.8	108.3	115.4	125.2	156.8	162.7	158.7
HKGSDC	COKE AND COKE OVEN GAS	187.3	178.3	187.6	195.2	202.3	209.4	214.6	227.9	245.6	264.8
HSTSDC	STEAM	34.0	32.2	34.7	38.4	40.8	41.4	41.6	40.2	45.6	51.9
HOFSDC	OTHER	365.5	388.5	391.9	400.6	405.5	406.8	411.3	427.2	448.4	469.8
	PRIMARY DEMAND BY SECTOR:										
HTSPDC	TOTAL	10016.1	10244.6	10548.3	10915.9	11161.5	11421.9	11710.6	12744.4	13892.9	15029.8
HTSEUC	END-USE DEMAND	6737.9	6713.5	6968.9	7213.0	7361.3	7518.6	7683.1	8260.0	8833.1	9450.8
HTSSDC	SECONDARY DEMAND	5996.0	6051.5	6135.1	6357.1	6503.8	6644.4	6792.0	7327.1	7814.3	8320.4
HTSRAC	RESIDENTIAL	1297.3	1284.6	1272.8	1316.0	1337.9	1370.1	1406.0	1498.1	1541.9	1571.4
HTSCPC	COMMERCIAL	903.6	903.6	915.0	964.9	1007.2	1048.1	1088.2	1223.8	1335.1	1425.1
HTSINC	INDUSTRIAL	2142.5	2198.2	2260.2	2384.1	2464.0	2518.3	2569.6	2765.8	2973.7	3235.8
HTSTRC	TRANSPORTATION	1652.6	1666.1	1687.2	1692.0	1694.6	1708.0	1728.2	1839.5	1963.5	2088.0
HTSNEC	NON-ENERGY USE	741.9	762.3	833.8	855.9	857.5	874.2	891.1	933.0	1018.8	1130.4
HELIRC	INTER-REG'L ELEC. TRANSFERS.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HTSPCC	PRODUCER CONSUMPTION	434.3	417.3	437.2	475.6	490.0	504.9	520.5	569.4	627.4	669.0
HTSCLC	INTERMEDIATE CONVERSION LOSS	2843.7	3013.3	3142.1	3227.3	3310.2	3398.4	3507.1	3915.0	4432.3	4910.0
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL.	10016.1	10244.6	10548.3	10915.9	11161.5	11421.9	11710.6	12744.4	13892.9	15029.8
HRPPDC	RPP'S	3019.9	3054.1	3159.5	3223.8	3246.5	3287.5	3367.3	3498.4	3774.7	3909.6
HNGPDC	NATURAL GAS	1977.1	1952.3	1969.5	2108.1	2165.9	2238.5	2273.1	2491.1	2696.7	2909.8
HLPPDC	LPG'S	178.8	184.3	214.7	222.5	231.1	260.5	280.6	335.5	368.5	396.9
HCCPDC	COAL	1140.2	1031.7	999.1	1018.5	1048.7	1050.6	1204.8	1472.1	1681.0	1907.4
HENPDC	NUCLEAR ELECTRICITY	599.5	716.2	822.9	877.6	944.1	1017.9	1009.7	1136.9	1130.0	1166.0
HEHPDC	HYDRO ELECTRICITY	2734.3	2891.7	2964.1	3017.2	3090.9	3127.9	3129.7	3341.6	3746.6	4221.8
HOFPDC	OTHER (RENEWABLES)	365.7	414.0	418.5	427.8	434.3	439.0	445.3	468.8	495.4	518.4
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2C	PRIMARY DEMAND - TOTAL	7824.7	7884.3	8059.7	8336.2	8509.9	8697.5	8990.4	9801.4	10688.2	11489.2
HEHP2C	HYDRO ELECTRICITY	937.5	991.4	1016.3	1034.5	1059.7	1072.4	1073.1	1145.7	1284.6	1447.5
HENP2C	NUCLEAR ELECTRICITY	205.5	245.5	282.1	300.9	323.7	349.0	346.2	389.8	387.4	399.8
	RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	131.99	126.18	122.78	125.05	124.99	125.98	127.16	128.67	124.73	120.13
RCDPRC	COM. DEMAND / COM. RDP	5.04	4.77	4.57	4.70	4.81	4.91	4.99	5.18	5.08	4.88
RIDPRC	IND. DEMAND / IND. RDP	20.42	20.67	20.98	21.03	21.06	21.10	21.11	20.99	20.44	20.15
RSDPCC	SECONDARY DEMAND / POP (GJ).	236.51	236.40	237.32	243.54	246.82	249.86	253.33	265.24	274.27	285.07
RSDPRC	" / RDP/	18.46	18.00	17.72	17.79	17.75	17.77	17.81	17.75	17.15	16.54
REUPCC	END-USE DEMAND / POP (GJ)	265.77	260.69	269.57	276.33	279.36	282.73	286.57	299.01	310.03	323.79
REUPRC	" " / RDP	20.74	19.85	20.12	20.18	20.09	20.11	20.15	20.01	19.38	18.79
RPDPCC	PRIMARY DEMAND / POP (GJ)	395.10	400.20	408.03	418.20	423.58	429.51	436.79	461.35	487.62	514.94
RPDPRC	" " / RDP	31.12	30.46	30.45	30.54	30.46	30.56	30.71	30.88	30.49	29.87

TABLE A.9.2: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES)

REGION: ATLANTIC

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDF	SECONDARY DEMAND BY FUEL:	445.8	458.1	465.0	486.2	504.5	518.0	533.7	591.1	616.8	645.4
HRPSDF	RPP'S	291.9	293.0	296.3	307.1	316.1	323.4	330.5	358.3	361.7	365.0
HNGSDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.0	29.4
HELSDF	ELECTRICITY	91.6	97.6	100.3	106.0	111.0	114.5	119.2	133.9	148.3	163.4
HCCSDF	COAL	3.1	2.4	2.9	4.1	5.3	6.2	7.3	10.4	6.1	4.7
HLPSDF	LPG'S	5.5	4.4	5.9	7.7	9.6	11.1	13.0	21.7	15.5	11.4
HKGSDF	COKE AND COKE OVEN GAS	3.1	9.8	10.1	10.5	10.8	11.0	11.3	12.0	13.0	13.1
HSTSDF	STEAM	6.7	1.4	0.2	0.3	0.3	0.4	0.4	0.6	0.4	0.4
HOFSDF	OTHER	43.8	49.4	49.2	50.4	51.2	51.4	52.0	54.1	56.8	58.0
	PRIMARY DEMAND BY SECTOR:										
HTSPDF	TOTAL	968.4	985.7	1007.4	1041.5	1049.5	1076.4	1171.0	1270.6	1323.2	1369.3
HTSEUF	END-USE DEMAND	463.9	475.4	484.1	505.7	524.6	538.3	554.4	613.4	640.0	669.7
HTSSDF	SECONDARY DEMAND	445.8	458.1	465.0	486.2	504.5	518.0	533.7	591.1	616.8	645.4
HTSRAF	RESIDENTIAL	85.2	84.9	87.2	91.6	95.7	99.7	102.9	111.3	110.5	114.3
HTSCPF	COMMERCIAL	62.8	61.9	63.0	66.5	70.0	71.8	74.3	85.7	89.1	96.0
HTSINF	INDUSTRIAL	151.5	165.2	166.1	176.8	185.7	190.8	198.6	223.1	233.4	242.3
HTSTRF	TRANSPORTATION	146.3	146.1	148.6	151.2	153.1	155.6	157.9	171.1	183.8	192.8
HTSNEF	NON-ENERGY USE	18.1	17.3	19.1	19.5	20.1	20.4	20.8	22.3	23.1	24.3
HELIRF	INTER-REG'L ELEC. TRANSFERS.	273.1	246.7	249.1	253.0	235.8	238.1	290.8	294.1	276.6	263.3
HTSPCF	PRODUCER CONSUMPTION	32.2	36.0	32.4	33.1	32.8	34.1	36.7	40.6	43.7	43.5
HTSCLF	INTERMEDIATE CONVERSION LOSS	199.1	227.6	241.8	249.7	256.4	265.8	289.0	322.5	362.9	392.9
HTSPDF	PRIMARY DEMAND BY FUEL - TOTAL.	968.4	985.7	1007.4	1041.5	1049.5	1076.4	1171.0	1270.6	1323.2	1369.3
HRPPDF	RPP'S	386.9	393.5	421.5	418.0	396.4	413.2	449.7	474.9	506.6	467.0
HNGPDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	16.4	31.2
HLPPDF	LPG'S	5.5	4.7	6.3	8.2	10.2	11.8	13.8	23.0	16.4	12.1
HCCPDF	COAL	83.9	86.3	86.5	102.2	110.0	114.5	136.6	200.7	217.1	232.1
HENPDF	NUCLEAR ELECTRICITY	57.0	54.9	53.1	46.6	46.5	46.2	46.6	47.1	47.2	47.2
HEHPDF	HYDRO ELECTRICITY	385.5	392.3	386.0	411.3	430.3	434.4	467.4	464.8	457.5	516.6
HOFPDF	OTHER (RENEWABLES)	43.8	53.6	54.0	55.2	56.0	56.3	56.9	59.3	62.1	63.2
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2F	PRIMARY DEMAND - TOTAL	676.8	691.5	718.8	740.6	736.2	760.6	833.3	934.3	991.5	998.8
HEHP2F	HYDRO ELECTRICITY	132.2	134.5	132.3	141.0	147.5	148.9	160.2	159.3	156.8	177.1
HENP2F	NUCLEAR ELECTRICITY	19.5	18.8	18.2	16.0	16.0	15.8	16.0	16.2	16.2	16.2
	RATIOS:										
RRDPHF	RES. DEMAND / HOUSEHOLD (GJ)	110.86	108.18	108.74	112.12	115.10	117.80	119.98	123.92	114.51	112.35
RCDPRF	COM. DEMAND / COM. RDP	4.65	4.40	4.26	4.42	4.59	4.62	4.73	5.09	4.67	4.66
RIDPRF	IND. DEMAND / IND. RDP	29.40	31.38	31.82	32.24	32.86	33.56	34.13	35.38	33.59	33.49
RSDPCF	SECONDARY DEMAND / POP (GJ)	193.30	195.83	196.70	203.58	209.09	212.54	217.01	232.13	233.24	236.44
RSDPRF	" / RDP/	21.55	21.59	21.44	21.78	22.12	22.30	22.73	23.27	21.86	21.46
REUPCF	END-USE DEMAND / POP (GJ)	201.13	203.23	204.77	211.75	217.41	220.90	225.46	240.89	242.00	245.34
REUPRF	" / RDP	22.42	22.40	22.32	22.66	23.00	23.17	23.62	24.15	22.68	22.26
RPDPCF	PRIMARY DEMAND / POP (GJ)	419.87	421.38	426.14	436.09	434.96	441.68	476.17	498.97	500.33	501.67
RPDPRF	" / RDP	46.80	46.45	46.45	46.66	46.02	46.33	49.88	50.02	46.90	45.52

TABLE A.9.3: SUMMARY RESULTS - ENERGY DEMAND REGION: QUEBEC
(PETAJOULES)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDQ	SECONDARY DEMAND BY FUEL:	1280.9	1320.5	1352.4	1399.4	1438.0	1465.1	1501.1	1613.7	1728.3	1855.0
HRPSDQ	RPP'S	535.6	536.8	538.7	546.9	554.5	562.8	573.4	603.8	625.2	650.7
HNGSDQ	NATURAL GAS	183.7	185.5	192.3	205.2	214.6	219.6	227.1	250.8	268.9	280.1
HELSDQ	ELECTRICITY	478.1	502.4	524.4	547.7	566.4	579.1	593.8	643.5	709.2	789.9
HCCSDQ	COAL	14.6	14.1	17.6	17.5	17.2	16.7	16.4	15.7	15.8	16.9
HLPSDQ	LPG'S	12.0	9.4	5.7	6.3	8.2	9.3	11.7	18.6	24.5	28.9
HKGSDQ	COKE AND COKE OVEN GAS	0.5	2.3	2.5	2.6	2.7	2.8	2.9	3.0	3.2	3.4
HSTSDQ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDQ	OTHER	56.5	69.9	71.1	73.1	74.4	74.8	75.8	78.3	81.5	85.1
	PRIMARY DEMAND BY SECTOR:										
HTSPDQ	TOTAL	2268.1	2379.0	2490.9	2575.4	2660.6	2709.4	2712.4	2949.6	3407.3	3798.1
HTSEUQ	END-USE DEMAND	1363.9	1397.4	1447.0	1494.8	1550.0	1577.8	1615.0	1735.1	1853.6	1988.8
HTSSDQ	SECONDARY DEMAND	1280.9	1320.5	1352.4	1399.4	1438.0	1465.1	1501.1	1613.7	1728.3	1855.0
HTSRAQ	RESIDENTIAL	269.2	271.9	268.2	276.5	282.7	289.3	295.0	313.4	327.6	339.2
HTSCPQ	COMMERCIAL	152.0	178.3	182.6	193.8	204.4	213.0	223.4	255.8	290.1	316.2
HTSINQ	INDUSTRIAL	510.1	518.0	540.2	568.6	589.8	599.6	615.7	660.4	709.4	776.6
HTSTRQ	TRANSPORTATION	349.6	352.5	361.4	360.5	361.1	363.1	366.9	384.0	401.2	423.0
HTSNEQ	NON-ENERGY USE	83.0	76.9	94.6	95.5	112.0	112.8	114.0	121.4	125.3	133.8
HELIRQ	INTER-REG'L ELEC. TRANSFERS.	-182.6	-170.3	-161.0	-180.7	-194.1	-202.0	-271.5	-269.4	-82.3	-12.6
HTSPCQ	PRODUCER CONSUMPTION	89.3	89.8	96.3	103.5	107.5	109.6	113.4	121.7	131.6	143.7
HTSCLQ	INTERMEDIATE CONVERSION LOSS	997.5	1062.1	1108.8	1157.8	1197.2	1223.9	1255.5	1362.2	1504.3	1678.1
HTSPDQ	PRIMARY DEMAND BY FUEL - TOTAL.	2268.1	2379.0	2490.9	2575.4	2660.6	2709.4	2712.4	2949.6	3407.3	3798.1
HRPPDQ	RPP'S	653.9	647.2	670.9	675.7	699.3	709.1	734.9	756.6	784.8	823.0
HNGPDQ	NATURAL GAS	185.3	186.8	202.0	215.2	224.8	230.0	237.6	261.7	280.1	291.5
HLPPDQ	LPG'S	17.5	13.7	17.7	12.5	14.5	15.7	18.8	34.5	44.5	53.5
HCCPDQ	COAL	21.5	22.8	26.6	26.8	26.7	26.3	26.2	25.9	26.4	28.1
HENPDQ	NUCLEAR ELECTRICITY	33.7	45.6	50.6	50.7	50.7	49.8	50.4	50.5	50.6	50.6
HEHPDQ	HYDRO ELECTRICITY	1299.8	1392.5	1459.9	1523.5	1570.0	1603.7	1568.8	1742.2	2139.3	2466.3
HOFPDQ	OTHER (RENEWABLES)	56.5	69.9	71.1	73.1	74.4	74.8	75.8	78.3	81.5	85.1
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Q	PRIMARY DEMAND - TOTAL	1391.9	1433.4	1498.3	1543.0	1595.5	1622.8	1648.4	1771.5	1968.2	2144.1
HEHP2Q	HYDRO ELECTRICITY	445.6	477.4	500.5	522.3	538.3	549.8	537.9	597.3	733.5	845.6
HENP2Q	NUCLEAR ELECTRICITY	11.6	15.6	17.4	17.4	17.4	17.1	17.3	17.3	17.3	17.3
	RATIOS:										
RRDPHQ	RES. DEMAND / HOUSEHOLD (GJ)	110.21	107.15	103.87	105.00	105.06	105.24	105.43	105.34	104.11	102.74
RCDPRQ	COM. DEMAND / COM. RDP	3.69	4.10	3.98	4.12	4.24	4.33	4.45	4.71	4.85	4.79
RIDPRQ	IND. DEMAND / IND. RDP	21.29	20.75	20.91	20.83	20.87	20.99	21.03	21.11	20.95	21.04
RSDPCQ	SECONDARY DEMAND / POP (GJ).	194.63	199.14	202.69	208.42	212.81	215.45	219.57	231.62	243.77	258.76
RSDPRQ	" / RDP/	17.29	17.16	16.94	16.93	16.89	16.89	17.04	16.95	16.61	16.33
REUPCQ	END-USE DEMAND / POP (GJ)	207.25	210.74	216.89	222.64	229.38	232.04	236.24	249.05	261.45	277.43
REUPRQ	" / RDP	18.41	18.16	18.13	18.09	18.20	18.19	18.33	18.22	17.82	17.50
RPDPCQ	PRIMARY DEMAND / POP (GJ)	344.65	358.78	373.34	383.58	393.73	398.44	396.76	423.37	480.59	529.80
RPDPRQ	" / RDP	30.61	30.92	31.20	31.16	31.24	31.23	30.79	30.98	32.75	33.43

TABLE A.9.4: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: ONTARIO

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDO	SECONDARY DEMAND BY FUEL:	2170.3	2199.5	2245.1	2326.5	2392.2	2467.7	2525.9	2764.0	2955.5	3128.1
HRPSDO	RPP'S	745.6	764.0	770.9	790.3	801.0	819.2	825.7	869.4	878.9	915.1
HNGSDO	NATURAL GAS	693.2	691.5	693.5	727.2	751.8	779.3	804.7	886.0	938.5	993.4
HELSDO	ELECTRICITY	405.8	427.9	443.5	454.2	469.1	486.5	502.9	587.2	681.0	733.5
HCCSDO	COAL	23.1	21.4	22.7	25.0	26.6	26.9	27.0	25.8	29.4	33.5
HLPSDO	LPG'S	25.2	28.8	35.6	38.6	42.2	45.6	50.0	66.3	72.4	68.1
HKGSDO	COKE AND COKE OVEN GAS	182.2	164.6	173.3	180.3	186.9	193.9	198.6	210.9	227.4	246.0
HSTSDO	STEAM	26.9	30.2	34.2	37.7	40.0	40.6	40.7	38.9	44.3	50.5
HOFSDO	OTHER	68.3	71.1	71.4	73.2	74.6	75.8	76.3	79.5	83.5	88.0
	PRIMARY DEMAND BY SECTOR:										
HTSPDO	TOTAL	3293.1	3372.9	3471.0	3623.7	3756.0	3873.3	3992.6	4434.3	4701.6	4964.2
HTSEUO	END-USE DEMAND	2405.8	2466.5	2530.0	2609.6	2676.7	2745.8	2807.5	3056.9	3271.5	3472.8
HTSSDO	SECONDARY DEMAND	2170.3	2199.5	2245.1	2326.5	2392.2	2467.7	2525.9	2764.0	2955.5	3128.1
HTSRAO	RESIDENTIAL	447.8	469.8	473.2	487.5	496.2	508.9	523.0	567.2	582.8	578.4
HTSCPO	COMMERCIAL	341.2	329.4	338.8	352.7	368.9	386.5	404.8	472.2	521.3	549.4
HTSINO	INDUSTRIAL	803.2	808.7	833.9	882.5	920.8	957.8	972.7	1056.4	1141.0	1249.3
HTSTRO	TRANSPORTATION	578.1	591.5	599.3	603.8	606.3	614.5	625.4	668.2	710.4	750.9
HTSNEO	NON-ENERGY USE	235.5	267.5	284.9	283.0	284.5	278.1	281.5	292.9	316.0	344.7
HELIRO	INTER-REG'L ELEC. TRANSFERS.	-100.7	-84.1	-100.1	-85.9	-55.4	-51.6	-34.8	-42.7	-208.6	-264.3
HTSPCO	PRODUCER CONSUMPTION	160.6	161.0	164.0	182.7	188.2	194.0	198.6	218.2	246.6	259.3
HTSCLO	INTERMEDIATE CONVERSION LOSS	827.4	829.5	877.6	917.3	946.5	985.1	1021.4	1201.9	1392.1	1496.4
HTSPDO	PRIMARY DEMAND BY FUEL - TOTAL.	3293.1	3372.9	3471.0	3623.7	3756.0	3873.3	3992.6	4434.3	4701.6	4964.2
HRPPDO	RPP'S	1019.9	1039.1	1077.1	1106.9	1115.5	1127.0	1135.8	1189.0	1348.6	1402.2
HNGPDO	NATURAL GAS	770.6	778.9	804.0	845.9	874.4	912.7	949.1	1055.4	1127.9	1202.6
HLPPDO	LPG'S	46.2	42.1	58.8	62.1	66.5	70.7	76.2	95.8	108.5	111.5
HCCPDO	COAL	539.6	452.5	393.1	439.5	458.3	440.3	521.4	654.3	681.5	716.1
HENPDO	NUCLEAR ELECTRICITY	508.8	615.6	719.2	780.3	846.9	921.9	912.7	1039.2	1032.2	1068.2
HEHPDO	HYDRO ELECTRICITY	339.7	368.6	369.4	317.3	318.0	322.6	318.6	317.8	316.1	371.1
HOFPDO	OTHER (RENEWABLES)	68.3	72.6	72.9	74.7	76.3	78.0	78.8	82.6	86.8	92.5
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2O	PRIMARY DEMAND - TOTAL	2735.5	2722.8	2756.2	2905.4	2990.5	3055.5	3183.5	3542.5	3815.6	4018.4
HEHP2O	HYDRO ELECTRICITY	116.5	126.4	126.7	108.8	109.0	110.6	109.2	109.0	108.4	127.2
HENP2O	NUCLEAR ELECTRICITY	174.5	211.1	246.6	267.5	290.4	316.1	312.9	356.3	353.9	366.3
	RATIOS:										
RRDPHO	RES. DEMAND / HOUSEHOLD (GJ)	132.89	135.18	132.82	133.80	133.36	134.46	135.96	138.67	134.94	127.55
RCDPRO	COM. DEMAND / COM. RDP	4.78	4.24	4.09	4.14	4.23	4.32	4.43	4.74	4.73	4.47
RIDPRO	IND. DEMAND / IND. RDP	16.41	15.97	16.31	16.44	16.55	16.68	16.69	16.73	16.39	16.14
RSDPCO	SECONDARY DEMAND / POP (GJ)	239.46	240.09	241.97	247.73	251.80	256.92	260.44	275.32	284.18	292.70
RSDPRO	" / RDP/	16.47	15.93	15.71	15.75	15.75	15.82	15.77	15.99	15.50	14.80
REUPCO	END-USE DEMAND / POP (GJ)	265.45	269.20	272.69	277.87	281.74	285.87	289.47	304.50	314.57	324.95
REUPRO	" / RDP	18.25	17.86	17.71	17.67	17.62	17.60	17.53	17.68	17.15	16.43
RPDPCO	PRIMARY DEMAND / POP (GJ)	363.35	368.17	378.90	385.86	395.34	403.25	411.67	441.70	452.08	464.50
RPDPRO	" / RDP	24.99	24.43	24.43	24.54	24.72	24.83	24.93	25.65	24.65	23.49

TABLE A.9.5: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: MANITOBA

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDM	SECONDARY DEMAND BY FUEL:	214.7	213.0	210.5	216.9	219.6	223.1	226.5	241.6	258.5	279.9
HRPSDM	RPP'S	97.5	95.3	97.5	100.1	101.2	102.4	103.3	110.7	119.5	128.5
HNGSDM	NATURAL GAS	62.3	60.4	57.4	60.5	61.2	62.6	64.1	67.1	69.0	70.6
HELSDM	ELECTRICITY	48.7	50.2	49.7	49.5	49.3	49.5	49.9	53.1	58.8	68.1
HCCSDM	COAL	2.6	2.7	2.7	3.4	3.9	4.1	4.2	4.7	4.4	4.8
HLPSDM	LPG'S	3.1	3.6	2.5	2.8	3.3	3.7	4.0	5.0	5.5	6.5
HKGSDM	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDM	STEAM	0.3	0.4	0.3	0.4	0.4	0.5	0.5	0.7	0.8	1.0
HOFSDM	OTHER	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
	PRIMARY DEMAND BY SECTOR:										
HTSPDM	TOTAL	367.9	370.5	367.0	379.5	383.2	390.4	395.4	424.2	453.6	499.0
HTSEUM	END-USE DEMAND	226.6	224.6	222.0	228.6	231.5	235.1	238.5	254.2	271.5	293.5
HTSSDM	SECONDARY DEMAND	214.7	213.0	210.5	216.9	219.6	223.1	226.5	241.6	258.5	279.9
HTSRAM	RESIDENTIAL	62.3	61.8	58.7	60.9	60.4	61.6	62.8	63.5	64.1	67.4
HTSCPM	COMMERCIAL	46.4	45.5	43.8	46.0	47.0	48.4	49.8	53.3	56.6	61.3
HTSINM	INDUSTRIAL	31.1	33.6	36.5	38.7	41.1	41.9	42.5	48.3	53.9	60.6
HTSTRM	TRANSPORTATION	74.9	72.0	71.4	71.4	71.2	71.3	71.4	76.5	83.9	90.6
HTSNEM	NON-ENERGY USE	11.9	11.6	11.5	11.7	11.8	12.0	12.0	12.5	13.0	13.6
HELIRM	INTER-REG'L ELEC. TRANSFERS.	13.5	9.0	10.2	14.6	14.7	16.6	16.5	19.0	15.4	14.7
HTSPCM	PRODUCER CONSUMPTION	17.7	17.6	18.6	20.5	21.6	22.7	23.5	26.4	29.0	31.7
HTSCLM	INTERMEDIATE CONVERSION LOSS	110.1	119.3	116.2	115.8	115.4	116.0	116.9	124.6	137.8	159.2
HTSPDM	PRIMARY DEMAND BY FUEL - TOTAL.	367.9	370.5	367.0	379.5	383.2	390.4	395.4	424.2	453.6	499.0
HRPPDM	RPP'S	102.5	99.9	102.2	105.0	106.2	107.5	108.5	116.4	125.6	135.2
HNGPDM	NATURAL GAS	79.2	77.7	73.8	78.7	80.6	83.1	85.3	90.5	93.7	96.2
HLPPDM	LPG'S	3.1	3.8	2.6	2.9	3.4	3.8	4.2	5.2	5.8	6.8
HCCPDM	COAL	7.0	5.7	5.6	6.4	6.9	7.2	7.4	8.1	8.0	8.7
HENPDM	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDM	HYDRO ELECTRICITY	175.8	182.9	182.2	185.9	185.4	188.1	189.4	203.4	219.8	251.5
HOFPDM	OTHER (RENEWABLES)	0.3	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2M	PRIMARY DEMAND - TOTAL	252.4	250.5	247.3	257.3	261.3	266.8	270.9	290.5	309.2	333.8
HEHP2M	HYDRO ELECTRICITY	60.3	62.7	62.5	63.7	63.6	64.5	64.9	69.7	75.3	86.2
HENP2M	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHM	RES. DEMAND / HOUSEHOLD (GJ)	135.21	127.98	117.91	121.30	117.77	117.89	118.29	117.42	114.73	114.04
RCDPRM	COM. DEMAND / COM. RDP	6.48	5.91	5.42	5.57	5.61	5.70	5.82	5.86	5.72	5.47
RIDPRM	IND. DEMAND / IND. RDP	12.45	12.66	13.57	13.94	14.36	14.09	14.39	15.18	15.22	15.28
RSDPCM	SECONDARY DEMAND / POP (GJ)	200.72	197.45	193.14	196.81	197.32	198.71	200.18	209.48	221.40	238.27
RSDPRM	" / RDP/	16.76	15.96	15.43	15.40	15.25	15.26	15.42	15.30	15.01	14.30
REUPCM	END-USE DEMAND / POP (GJ)	211.81	208.21	203.72	207.41	207.95	209.36	210.81	220.33	232.51	249.82
REUPRM	" / RDP	17.69	16.83	16.27	16.23	16.07	16.08	16.24	16.09	15.76	14.99
RPDPCM	PRIMARY DEMAND / POP (GJ)	343.92	343.51	336.73	344.28	344.29	347.65	349.50	367.73	388.46	424.76
RPDPRM	" / RDP	28.73	27.76	26.89	26.94	26.61	26.71	26.93	26.86	26.34	25.49

TABLE A.9.6: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: SASKATCHEWAN

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDS	SECONDARY DEMAND BY FUEL:	283.4	273.7	270.1	278.7	281.5	285.5	289.2	309.4	338.0	370.4
HRPSDS	RPP'S	125.6	123.4	121.1	122.3	122.1	122.6	122.7	125.9	136.0	148.5
HNGSDS	NATURAL GAS	102.2	94.4	90.9	98.2	101.5	104.8	108.2	120.1	126.8	131.8
HELSDS	ELECTRICITY	36.8	37.6	39.1	38.4	37.6	37.4	37.4	41.5	51.8	64.1
HCCSDS	COAL	4.3	3.0	4.0	4.5	5.0	5.3	5.7	6.2	6.8	8.0
HLPSDS	LPG'S	4.8	4.6	4.2	4.0	3.8	3.7	3.6	3.5	3.7	4.1
HKGSDS	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDS	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDS	OTHER	9.7	10.8	10.8	11.3	11.5	11.5	11.6	12.1	13.0	14.0
	PRIMARY DEMAND BY SECTOR:										
HTSPDS	TOTAL	433.5	409.2	417.0	424.2	427.1	432.9	438.2	478.1	544.1	618.2
HTSEUS	END-USE DEMAND	294.6	285.5	280.5	289.7	292.9	297.2	301.2	322.9	353.4	387.8
HTSSDS	SECONDARY DEMAND	283.4	273.7	270.1	278.7	281.5	285.5	289.2	309.4	338.0	370.4
HTSRAS	RESIDENTIAL	91.1	89.9	87.6	90.8	92.2	94.5	96.0	101.3	107.0	112.0
HTSCPS	COMMERCIAL	41.0	39.8	40.8	44.2	44.1	44.5	44.6	46.0	48.2	51.2
HTSINS	INDUSTRIAL	75.3	70.8	69.0	71.8	73.6	74.9	77.0	85.1	96.2	110.9
HTSTRS	TRANSPORTATION	76.0	73.1	72.7	72.0	71.7	71.5	71.7	77.0	86.6	96.3
HTSNES	NON-ENERGY USE	11.2	11.8	10.5	11.0	11.5	11.7	12.0	13.5	15.4	17.4
HELIRS	INTER-REG'L ELEC. TRANSFERS.	-3.4	-1.4	1.8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
HTSPCS	PRODUCER CONSUMPTION	29.3	27.0	28.3	32.1	34.2	36.4	37.9	43.8	48.4	51.9
HTSCLS	INTERMEDIATE CONVERSION LOSS	113.0	98.1	106.4	103.4	101.0	100.4	100.1	112.4	143.3	179.5
HTSPDS	PRIMARY DEMAND BY FUEL - TOTAL.	433.5	409.2	417.0	424.2	427.1	432.9	438.2	478.1	544.1	618.2
HRPPDS	RPP'S	141.6	138.9	136.1	137.9	138.0	138.8	139.2	144.1	156.4	171.4
HNGPDS	NATURAL GAS	126.1	119.9	118.0	129.1	134.6	140.2	145.2	162.1	171.8	178.4
HLPPDS	LPG'S	4.9	4.6	4.2	4.0	3.9	3.8	3.7	3.5	3.7	4.1
HCCPDS	COAL	131.5	94.2	106.8	100.7	97.7	97.5	97.2	114.6	157.4	205.6
HENPDS	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDS	HYDRO ELECTRICITY	19.6	39.4	39.5	39.6	39.7	39.3	39.6	39.7	39.5	41.9
HOFPDS	OTHER (RENEWABLES)	9.7	12.4	12.4	12.9	13.2	13.4	13.5	14.1	15.2	16.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2S	PRIMARY DEMAND - TOTAL	420.6	383.4	391.0	398.2	401.1	407.1	412.2	452.0	518.1	590.6
HEHP2S	HYDRO ELECTRICITY	6.7	13.5	13.5	13.6	13.6	13.5	13.6	13.6	13.5	14.4
HENP2S	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHS	RES. DEMAND / HOUSEHOLD (GJ)	171.91	158.30	151.61	156.21	155.59	156.53	157.08	160.27	157.46	154.07
RCDPRS	COM. DEMAND / COM. RDP	7.24	6.74	6.63	7.03	6.83	6.80	6.67	6.29	5.77	5.35
RIDPRS	IND. DEMAND / IND. RDP	29.41	30.04	29.33	27.80	27.50	27.86	28.29	28.72	28.33	28.32
RSDPCS	SECONDARY DEMAND / POP (GJ)	278.75	264.52	257.26	262.13	261.41	261.76	262.17	268.69	280.08	294.39
RSDPRS	" / RDP/	23.49	22.01	21.49	21.45	21.04	21.10	21.04	20.64	19.97	19.29
REUPCS	END-USE DEMAND / POP (GJ)	289.76	275.97	267.24	272.51	272.05	272.46	273.06	280.43	292.85	308.21
REUPRS	" / RDP	24.42	22.96	22.32	22.30	21.89	21.97	21.92	21.54	20.88	20.19
RPDPCS	PRIMARY DEMAND / POP (GJ)	426.36	395.51	397.22	398.98	396.65	396.88	397.23	415.16	450.83	491.35
RPDPRS	" / RDP	35.93	32.90	33.18	32.65	31.92	32.00	31.88	31.89	32.14	32.19

TABLE A.9.7: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: ALBERTA

		FORECAST 1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDA	SECONDARY DEMAND BY FUEL:	792.9	793.8	792.0	821.8	828.5	839.3	855.1	910.3	978.6	1042.3
HRPSDA	RPP'S	295.5	307.6	310.7	320.4	317.7	315.5	317.5	329.3	354.4	382.3
HNGSDA	NATURAL GAS	340.4	326.0	313.1	329.3	337.5	347.7	358.1	386.0	408.6	428.8
HELSDA	ELECTRICITY	111.3	114.9	120.8	123.0	124.6	127.3	130.3	146.0	167.1	183.8
HCCSDA	COAL	1.7	1.4	1.6	1.4	1.3	1.2	1.1	0.7	0.1	0.1
HLPSDA	LPG'S	24.7	22.7	24.9	26.2	25.6	25.6	25.7	24.6	22.8	20.2
HKGSDA	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDA	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDA	OTHER	19.1	21.1	20.9	21.6	21.8	22.0	22.4	23.8	25.6	27.0
	PRIMARY DEMAND BY SECTOR:										
HTSPDA	TOTAL	1460.1	1488.6	1528.4	1595.2	1586.9	1627.3	1662.8	1783.4	1963.2	2144.2
HTSEUA	END-USE DEMAND	1133.6	1122.1	1155.7	1206.9	1193.0	1225.3	1252.6	1328.0	1450.6	1580.0
HTSSDA	SECONDARY DEMAND	792.9	793.8	792.0	821.8	828.5	839.3	855.1	910.3	978.6	1042.3
HTSRAA	RESIDENTIAL	218.0	192.2	186.6	193.8	195.1	198.7	207.0	221.3	230.5	238.2
HTSCPA	COMMERCIAL	152.0	145.2	143.6	151.6	157.7	164.4	168.5	180.3	192.1	205.7
HTSINA	INDUSTRIAL	198.2	234.9	241.1	255.5	255.2	254.9	256.5	267.2	291.6	313.7
HTSTRA	TRANSPORTATION	224.7	221.6	220.7	220.9	220.5	221.3	223.1	241.5	264.3	284.7
HTSNEA	NON-ENERGY USE	340.8	328.1	363.7	385.1	364.5	386.0	397.5	417.7	472.0	537.7
HELIRA	INTER-REG'L ELEC. TRANSFERS.	-0.4	0.7	-5.6	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
HTSPCA	PRODUCER CONSUMPTION	53.3	59.0	59.4	62.6	63.8	65.0	65.8	70.8	76.8	82.5
HTSCLA	INTERMEDIATE CONVERSION LOSS	273.5	306.9	318.9	330.4	334.8	341.8	349.0	389.3	440.6	486.5
HTSPDA	PRIMARY DEMAND BY FUEL - TOTAL.	1460.1	1488.6	1528.4	1595.2	1586.9	1627.3	1662.8	1783.4	1963.2	2144.2
HRPPDA	RPP'S	371.7	387.5	392.5	405.2	408.5	406.5	409.1	421.9	450.6	484.9
HNGPDA	NATURAL GAS	616.5	585.9	592.0	658.3	667.9	672.0	643.7	684.5	748.9	817.4
HLPPDA	LPG'S	91.9	104.6	118.4	118.3	116.8	138.0	146.5	156.0	171.0	189.0
HCCPDA	COAL	346.2	361.0	376.3	338.0	343.6	359.4	410.4	462.9	529.8	589.1
HENPDA	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDA	HYDRO ELECTRICITY	14.6	19.0	18.9	18.9	18.4	18.0	18.3	17.6	16.3	15.8
HOFPDA	OTHER (RENEWABLES)	19.1	30.6	30.3	31.1	31.8	33.4	34.8	40.5	46.7	48.1
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2A	PRIMARY DEMAND - TOTAL	1450.4	1476.1	1516.0	1557.4	1574.8	1615.5	1650.8	1771.8	1952.5	2133.9
HEHP2A	HYDRO ELECTRICITY	5.0	6.5	6.5	6.5	6.3	6.2	6.3	6.0	5.6	5.4
HENP2A	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHA	RES. DEMAND / HOUSEHOLD (GJ)	223.94	183.34	176.85	185.07	185.65	187.42	190.07	189.27	175.70	165.10
RCDPRA	COM. DEMAND / COM. RDP	8.26	7.82	7.45	7.69	7.94	8.15	8.13	7.85	7.31	6.94
RIDPRA	IND. DEMAND / IND. RDP	18.08	22.95	24.11	23.88	23.35	22.93	22.27	20.66	19.44	18.79
RSDPCA	SECONDARY DEMAND / POP (GJ)	336.36	339.49	337.90	349.24	350.54	352.99	357.55	369.09	380.82	391.56
RSDPRA	" / RDP/	22.11	22.44	22.25	22.29	22.18	22.10	21.99	21.10	19.94	19.06
REUPCA	END-USE DEMAND / POP (GJ)	480.92	472.20	493.05	512.92	504.73	515.35	523.75	538.43	564.49	593.55
REUPRA	" / RDP	31.61	31.22	32.46	32.74	31.93	32.26	32.21	30.78	29.56	28.89
RPDPCA	PRIMARY DEMAND / POP (GJ)	619.42	636.40	653.70	677.92	671.40	684.44	695.25	723.09	764.00	805.52
RPDPRA	" / RDP	40.71	42.07	42.93	43.28	42.47	42.84	42.75	41.33	40.01	39.21

TABLE A.9.8: SUMMARY RESULTS - ENERGY DEMAND
(PETAJOULES)

REGION: B.C.+YK.+N.W.T.

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDZ	SECONDARY DEMAND BY FUEL:	808.2	793.0	800.2	827.6	839.4	845.7	860.5	896.9	938.6	999.3
HRPSDZ	RPP'S	297.5	296.8	304.7	317.9	322.5	325.1	329.4	335.8	343.2	362.8
HNGSDZ	NATURAL GAS	165.9	147.6	141.6	147.8	149.2	150.6	154.2	166.1	173.1	179.2
HELSDZ	ELECTRICITY	163.9	165.9	169.3	172.3	175.2	177.3	181.4	193.4	211.0	234.9
HCCSDZ	COAL	1.9	4.7	2.5	3.2	3.5	3.6	3.8	3.6	3.3	3.3
HLPSDZ	LPG'S	9.6	10.5	12.4	14.2	15.6	16.4	17.1	17.1	18.3	19.5
HKGSDZ	COKE AND COKE OVEN GAS	1.5	1.6	1.7	1.7	1.7	1.7	1.8	1.9	2.0	2.2
HSTSDZ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDZ	OTHER	168.0	165.9	168.2	170.5	171.7	171.0	172.9	179.1	187.7	197.3
	PRIMARY DEMAND BY SECTOR:										
HTSPDZ	TOTAL	1224.7	1219.1	1241.2	1276.5	1298.2	1312.3	1338.2	1404.2	1499.9	1636.7
HTSEUZ	END-USE DEMAND	849.7	839.0	849.4	877.6	892.6	899.0	913.8	949.5	992.5	1058.2
HTSSDZ	SECONDARY DEMAND	808.2	793.0	800.2	827.6	839.4	845.7	860.5	896.9	938.6	999.3
HTSRAZ	RESIDENTIAL	123.7	114.0	111.2	115.0	115.7	117.3	119.4	120.2	119.4	121.9
HTSCPZ	COMMERCIAL	108.4	103.4	102.5	110.1	115.1	119.5	122.8	130.4	137.7	145.3
HTSINZ	INDUSTRIAL	373.2	367.0	373.3	390.2	397.9	398.3	406.6	425.2	448.0	482.3
HTSTRZ	TRANSPORTATION	202.9	209.2	213.1	212.3	210.8	210.6	211.8	221.2	233.5	249.9
HTSNEZ	NON-ENERGY USE	41.5	46.0	49.2	50.0	53.3	53.3	53.3	52.6	54.0	58.9
HELIRZ	INTER-REG'L ELEC. TRANSFERS	0.3	-0.7	5.5	4.7	4.7	4.7	4.7	4.7	4.7	4.7
HTSPCZ	PRODUCER CONSUMPTION	51.9	43.2	38.2	41.2	42.0	43.1	44.5	48.0	51.5	56.4
HTSCLZ	INTERMEDIATE CONVERSION LOSS	322.7	337.6	348.0	352.9	358.8	365.4	375.1	402.0	451.2	517.3
HTSPDZ	PRIMARY DEMAND BY FUEL - TOTAL	1224.7	1219.1	1241.2	1276.5	1298.2	1312.3	1338.2	1404.2	1499.9	1636.7
HRPPDZ	RPP'S	343.4	348.1	359.1	375.2	382.6	385.4	390.1	395.6	402.0	425.9
HNGPDZ	NATURAL GAS	199.4	179.5	179.7	180.8	183.4	200.5	212.2	236.1	257.9	292.5
HLPPDZ	LPG'S	9.7	10.8	12.6	14.5	15.9	16.7	17.4	17.5	18.6	19.9
HCCPDZ	COAL	5.5	9.2	4.3	5.1	5.4	5.5	5.7	5.6	60.7	127.8
HENPDZ	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDZ	HYDRO ELECTRICITY	499.2	497.0	508.3	520.8	529.0	521.8	527.8	556.1	558.2	558.5
HOFPDZ	OTHER (RENEWABLES)	168.0	174.3	177.2	180.1	181.8	182.4	184.9	193.4	202.5	212.1
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Z	PRIMARY DEMAND - TOTAL	897.0	892.3	907.1	934.3	950.6	969.4	991.4	1038.8	1133.1	1269.6
HEHP2Z	HYDRO ELECTRICITY	171.2	170.4	174.3	178.6	181.4	178.9	181.0	190.7	191.4	191.5
HENP2Z	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHZ	RES. DEMAND / HOUSEHOLD (GJ)	106.95	97.53	94.09	96.78	96.80	97.93	98.94	98.31	94.20	90.76
RCDPRZ	COM. DEMAND / COM. RDP	5.30	4.66	4.41	4.68	4.83	4.97	5.03	4.99	4.78	4.54
RIDPRZ	IND. DEMAND / IND. RDP	36.33	35.79	35.45	36.03	36.26	36.59	36.54	35.64	34.18	33.31
RSDPCZ	SECONDARY DEMAND / POP (GJ)	273.22	262.95	262.01	267.80	268.51	267.68	269.71	271.77	275.01	284.95
RSDPRZ	" " / RDP/	21.53	20.39	19.99	20.28	20.25	20.29	20.38	19.82	18.97	18.31
REUPCZ	END-USE DEMAND / POP (GJ)	287.25	278.20	278.30	284.00	285.55	284.55	286.41	287.71	290.82	301.75
REUPRZ	" " / RDP	22.63	21.57	21.22	21.50	21.54	21.56	21.64	20.98	20.06	19.39
RPDPCZ	PRIMARY DEMAND / POP (GJ)	414.10	404.25	406.40	413.06	415.29	415.34	419.42	425.48	439.49	466.70
RPDPRZ	" " / RDP	32.65	31.35	31.00	31.28	31.33	31.48	31.69	31.02	30.32	29.98

Appendix B: Summary Tables for the $15-24 Scenario

B.1 Macroeconomic Assumptions

B.2 World and Domestic Crude Oil Prices

B.3 Domestic Export Natural Gas Prices

B.4 Electricity Price Determination

B.5 Comparative Fuel Prices by Sector

B.6 Supply and Demand for Petroleum

B.7 Supply and Demand for Natural Gas and LPGs

B.8 Electricity Supply and Demand

B.9 Summary Results - Energy Demand

TABLE B.1: MACROECONOMIC ASSUMPTIONS REGION: CANADA

		FORECAST 1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	OUTPUT AND INCOME: (1981=100.0) (CONSTANT 81$)										
GNIK	REAL GNE	108.33	111.57	114.92	118.83	121.44	124.12	126.85	138.38	154.29	172.02
RDIC	RDP - TOTAL	106.97	110.73	114.03	117.77	120.95	123.97	126.70	138.22	154.11	171.82
RDIAGC	- AGRICULTURE	101.11	109.01	106.80	106.65	112.83	115.54	118.31	130.09	146.47	164.91
RDIINC	- INDUSTRIAL	103.62	105.06	106.43	112.17	116.21	119.93	122.81	133.98	149.38	166.55
RDIIRC	- IRON & STEEL (NAT'L)	103.28	100.80	102.61	108.77	112.69	116.52	119.78	133.77	153.58	176.32
RDICIC	- COMMERCIAL & PUBLIC ADMIN	110.06	116.43	123.04	126.22	128.99	131.96	135.00	147.85	165.65	185.60
RDIAVC	- AVIATION (NAT'L)	110.71	112.07	103.01	109.36	113.53	116.71	119.98	133.99	153.83	176.60
RDIRLC	- RAIL (NAT'L)	101.47	100.50	98.57	101.97	104.49	107.10	109.77	121.17	137.09	155.11
RDIICC	RDP PER CAPITA	102.66	105.24	107.31	109.77	111.67	113.42	114.97	121.74	131.60	143.23
YIDKC	REAL PERSONAL DISPOSABLE INCOME	105.56	106.83	108.43	110.17	111.93	113.72	115.54	123.11	133.28	144.29
YIDICC	PERS'L DISP. INCOME PER CAPITA	101.30	101.53	102.05	102.68	103.34	104.04	104.85	108.43	113.81	120.28
	PRICES AND COSTS: (1981=1.0)										
PWPIUS	U.S. WPI (1967=100.0)	308.7	297.6	304.4	312.7	325.2	338.2	351.7	411.4	500.6	609.0
PGDP	GDP DEFLATOR - TOTAL	1.250	1.266	1.321	1.361	1.420	1.479	1.541	1.817	2.232	2.742
PGDPAG	- AGRICULTUPAL	0.953	0.936	0.911	0.930	0.950	0.977	1.005	1.127	1.300	1.500
PGDPIN	- INDUSTRIAL	1.262	1.326	1.392	1.420	1.460	1.519	1.579	1.848	2.248	2.735
PGDPCP	- COMMERCIAL	1.271	1.345	1.434	1.517	1.602	1.681	1.763	2.135	2.712	3.445
PCXDE	PERS. CONS. DEFLATOR EX. ENERGY	1.262	1.322	1.383	1.448	1.513	1.581	1.653	1.973	2.461	3.069
CPI	CONSUMER PRICE INDEX	1.271	1.325	1.379	1.439	1.500	1.566	1.634	1.933	2.386	2.946
PFX	EXCHANGE RATE ($CDN/$US)	1.366	1.390	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330
RIPRVB	AVG. YIELD - 10 PROV'L BONDS	11.7	9.5	9.8	9.6	9.8	9.4	9.4	9.4	9.4	9.4
	DEMOGRAPHIC: ('000)										
POPC	TOTAL POPULATION	25352.	25598.	25852.	26102.	26350.	26593.	26811.	27624.	28491.	29188.
HHC	TOTAL HOUSEHOLDS	9079.	9334.	9513.	9686.	9851.	10011.	10159.	10717.	11362.	11964.
RHHSTC	SINGLE / MULTIPLE HOUSEHOLDS	0.652	0.668	0.667	0.667	0.667	0.666	0.666	0.666	0.667	0.667
	LABOUR FORCE: ('000)										
POPLFC	LABOUR FORCE SOURCE POPULATION	19372.	19602.	19851.	20091.	20324.	20552.	20760.	21556.	22474.	23288.
LFC	LABOUR FORCE	12639.	12877.	13114.	13282.	13449.	13581.	13749.	14326.	14871.	15291.
EMPC	TOTAL EMPLOYMENT	11311.	11635.	11900.	12100.	12303.	12439.	12575.	13125.	13795.	14498.
URATEC	UNEMPLOYMENT RATE (%)	10.51	9.65	9.26	8.90	8.52	8.41	8.54	8.38	7.24	5.18
	PASSENGER VEHICLES:										
NPVSTC	SALES - VOLUME ('000)	1137.2	1059.1	1029.8	1101.9	1128.6	1185.2	1232.7	1327.4	1449.4	1578.7
ENPVS	- EFFICIENCY (L/100KM)	10.6	10.6	10.7	10.6	10.6	10.7	11.0	10.3	10.1	10.1
KTPVSC	STOCK - VOLUME ('000)	9576.5	9713.4	9815.5	9988.6	10189.9	10444.2	10736.3	11988.0	13466.4	14826.1
EKTPVC	- EFFICIENCY (L/100KM)	12.3	12.3	12.0	11.7	11.4	11.2	11.1	10.8	10.4	10.2
KTMAC	MANUFAC'NG CAPITAL STOCK ($81B)	118.947	122.337	125.835	129.434	133.162	136.504	139.303	152.745	168.179	191.218
KGDSC	NATURAL GAS DIST. CAPACITY (MCM)	830.	841.	849.	853.	856.	863.	869.	899.	929.	953.
DDAYSC	HEATING DEGREE DAYS (NORM=1)	1.013	0.962	0.926	1.000	1.000	1.000	1.000	1.000	1.000	1.000

TABLE B.2: WORLD AND DOMESTIC CRUDE OIL PRICES
($/CUBIC METRE)

		FORECAST								
	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	WEST TEXAS INTERMEDIATE: ($US)									
PWTCU	CUSHING	176.20	94.77	121.33	99.21	103.18	107.31	120.53	189.74	242.49	310.49
PWTCUR	REAL ($1986)	171.52	94.77	118.37	94.39	94.39	94.39	101.94	137.18	144.11	151.66
TOCUCH	TRANSPORTATION TO CHICAGO	2.83	2.32	2.84	2.88	2.94	3.00	3.06	3.31	3.65	4.04
TRFDU	U.S. REFINERY TAX	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
PWTCH	CHICAGO	179.53	97.59	124.67	102.59	106.62	110.81	124.09	193.55	246.65	315.03
	BRENT ($US)									
PBRNS	NORTH SEA (F.O.B)	173.95	91.54	117.65	95.13	99.05	103.09	116.11	184.31	236.19	303.11
TOLOSS	OCEAN LOSS	0.70	0.37	0.47	0.38	0.40	0.41	0.46	0.74	0.94	1.21
TONSPO	TRANSPORTATION TO PORTLAND	5.51	5.12	4.63	4.70	4.79	4.89	4.98	5.39	5.96	6.58
TOPOMO	TRANSPORTATION TO MONTREAL	5.30	3.97	4.14	4.19	4.28	4.36	4.45	4.82	5.32	5.87
PBRMO	MONTREAL (C.I.F)	185.46	101.00	126.89	104.40	108.51	112.75	126.01	195.26	248.41	316.77
	LANDED IMPORT COST:									
PCRICA	IMPORT MIX ADJUSTMENT	-5.35	2.41	-7.93	-7.31	-7.60	-7.89	-8.82	-13.67	-17.39	-22.17
PCRMU	AT MONTREAL (CIF)($US)	180.11	103.41	118.96	97.09	100.92	104.86	117.18	181.59	231.02	294.59
PFX	EXCHANGE RATE($CDN/$US)	1.366	1.390	1.330	1.330	1.330	1.330	1.330	1.330	1.330	1.330
PCRMT	AT MONTREAL (CIF)($CDN)	250.33	143.74	158.22	129.13	134.22	139.46	155.86	241.51	307.26	391.81
	CANADIAN PAR:									
PPACH	CHICAGO ($US)	183.08	98.95	123.55	102.59	106.62	110.81	124.09	193.55	246.65	315.03
TRFPAU	U.S. IMPORT TARIFFS	0.66	0.83	1.60	1.60	1.57	1.58	1.60	1.72	1.81	1.92
TOBOCH	TRANSPORTATION TO U.S. BORDER	3.06	2.97	2.97	3.01	3.07	3.13	3.19	3.46	3.82	4.21
TOBOED	TRANSPORTATION TO EDMONTON	1.60	1.77	2.27	2.30	2.35	2.40	2.45	2.67	2.96	3.28
PPAED	EDMONTON ($CDN)	242.82	129.80	155.22	127.25	132.50	137.91	155.40	246.99	316.63	406.46
	REFINERY CRUDE COST ($CDN):									
PCRATA	ALBERTA	234.98	124.48	149.64	122.80	127.87	133.09	149.96	238.35	305.55	392.24
PCRATO	ONTARIO	242.14	132.12	156.45	135.60	133.79	139.12	153.58	243.81	311.21	398.01
PCRATQ	QUEBEC	244.66	133.36	159.33	139.84	136.49	141.88	155.82	246.59	314.20	401.21
PCRATF	ATLANTIC	224.15	140.81	155.65	123.56	128.53	133.66	149.94	235.11	300.19	384.00

TABLE B.3: DOMESTIC AND EXPORT NATURAL GAS PRICES
($/GIGAJOULE)

		FORECAST 1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	DOMESTIC PRICE:										
PNGAB	AVERAGE ALBERTA BORDER.....	2.80	2.66	1.87	1.89	2.03	2.05	2.24	4.04	5.48	7.39
PNGABR	RESIDENTIAL.....	2.80	2.[illegible]	2.24	2.09	2.31	2.32	2.54	4.04	5.48	7.39
PNGABC	COMMERCIAL.....	2.80	2.69	2.14	2.03	2.23	2.24	2.44	4.04	5.48	7.39
PNGABI	INDUSTRIAL.....	2.80	2.41	1.68	1.69	1.77	1.78	1.96	4.04	5.48	7.39
PGDSAB	DIRECT SALES.....	2.80	2.30	1.20	1.31	1.54	1.66	1.96	4.04	5.48	7.39
PCMPAB	CMP'S.....	2.80	2.42	1.80	1.83	1.85	1.82	1.96	4.04	5.48	7.39
GOPAR	TORONTO GAS/OIL PARITY.....	0.60	0.99	0.74	0.86	0.92	0.89	0.86	0.84	0.86	0.87
	EXPORT PRICE:										
PNGXT	EXPORT PRICE ($CDN).....	4.09	3.21	2.43	2.42	2.56	2.60	2.80	4.66	6.17	8.16
PFX	EXCHANGE RATE ($CDN/$US).....	1.37	1.39	1.33	1.33	1.33	1.33	1.33	1.33	1.33	1.33
PNGXU	EXPORT PRICE ($US).....	3.00	2.31	1.83	1.82	1.93	1.95	2.11	3.50	4.64	6.13

TABLE B.4: ELECTRICITY PRICE DETERMINATION (NOMINAL) REGION: CANADA

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	UTILITY FUEL INPUT PRICES: ($/GJ)										
PCCUEC	COAL	1.450	1.371	1.274	1.465	1.542	1.551	1.685	2.187	2.589	2.925
PHFUEC	HEAVY FUEL OIL	5.354	3.307	3.345	2.486	2.585	2.686	3.057	5.016	5.148	6.633
PDSUEC	DISTILLATES	9.419	5.999	7.088	6.369	6.549	6.839	7.408	10.671	13.671	17.777
PNGUEC	NATURAL GAS	2.193	2.307	2.206	1.898	1.582	2.019	2.830	5.395	7.087	9.218
PNUUEC	NUCLEAR	0.385	0.408	0.426	0.439	0.458	0.477	0.497	0.586	0.720	0.884
POFUEC	OTHER FUELS	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	PLANNED COSTS: ($MILLIONS)										
FPETTC	TOTAL PLANNED COSTS	16097.0	16883.0	18269.4	18790.0	19488.8	20210.9	21311.0	27234.7	36114.7	50231.4
FPEOCC	PLANNED OPERATING COSTS	6196.4	6133.9	6605.1	6781.9	7066.0	7498.0	8284.5	11629.6	16704.2	22490.4
FPFULC	PLANNED FUEL COSTS	1861.9	1634.0	1735.2	1849.2	1887.1	2015.0	2416.5	4026.3	6304.3	8329.7
FIWSAC	WAGES AND SALARIES	2679.4	2679.4	2877.9	2970.8	3142.9	3313.0	3568.0	4655.0	6404.1	8867.4
FPEOOC	OTHER OPERATING COSTS	624.2	696.9	785.4	778.4	804.1	862.9	922.5	1215.9	1683.8	2269.1
FITXSC	INDIRECT TAXES	679.7	732.6	732.7	750.2	780.4	825.2	864.6	1060.7	1358.6	1728.9
FIROYC	ROYALTIES	351.2	391.0	473.8	433.3	451.5	482.0	512.9	671.7	953.3	1295.4
FIEFXC	FIXED COSTS	7844.7	8300.7	9011.0	9389.6	9655.8	9992.7	10235.5	12079.8	15301.4	21269.7
FIINTC	NET INTEREST COSTS	5952.8	6277.1	6823.6	7121.5	7268.4	7532.4	7628.4	8909.6	11225.1	15711.2
FIDEPC	DEPRECIATION	1891.9	2023.5	2187.5	2268.0	2387.3	2460.3	2607.1	3170.2	4076.3	5558.5
FIRETC	TOTAL RETURN ON NET EQUITY	1048.9	1496.0	1770.1	1772.5	1960.1	1994.8	2144.8	2902.3	3425.4	5676.6
FICRPC	PLANNED CONTRIB'N TO RESERVE	18.8	0.0	-8.4	-6.5	-17.6	-83.4	-152.5	-181.6	-205.8	-243.0
FPFEXC	PLANNED EXCHANGE LOSS	548.8	464.3	379.3	330.0	287.1	249.8	217.3	124.5	62.1	30.9
FIITXC	INCOME TAX	284.8	302.9	317.9	324.2	333.4	346.8	360.7	421.9	513.3	624.5
FIEOXC	OTHER EXPENSES	154.4	185.3	194.5	198.4	204.0	212.2	220.7	258.2	314.1	382.2
	OTHER REVENUE FLOWS: ($MILLION)										
FISAXC	FROM NET EXTERNAL SALES	1389.7	1061.7	1481.7	1051.4	921.3	957.3	1009.4	2061.2	2548.4	3325.6
FMRESC	EXTERNAL SALES	2055.8	1061.7	1741.7	1297.5	1107.9	1141.3	1185.1	2274.0	3803.3	5398.3
FMCEPC	EXTERNAL PURCHASES	406.5	0.0	260.0	246.	186.6	184.1	175.7	212.8	1254.9	2072.8
FISUBC	SUBSIDIES	26.1	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9
FIROTC	OTHER OPERATING REVENUE	88.9	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4	451.4
FIOTIC	OTHER INCOME	839.8	666.2	699.2	713.2	733.5	762.9	793.4	928.2	1129.2	1373.9
FMRRQC	PLANNED DOMESTIC REVENUE REQUIREMENTS ($MILLIONS)	13752.8	14701.8	15635.1	16572.1	17380.6	18037.4	19054.9	23792.0	31983.7	45078.6
VEUIPC	PLANNED INTERNAL SALES (GHW)	334576.	350762.	364095.	374804.	385889.	398664.	409041.	457760.	525677.	589285.
	AVERAGE PRICES: (CENTS/KWH)										
PELCAC	BASED ON REVENUE REQUIREMENTS	4.111	4.275	4.382	4.493	4.554	4.559	4.710	5.268	6.148	7.576
PELAAC	ANNOUNCED PRICES	4.111	4.563	4.420	4.501	4.544	4.683	4.729	5.223	6.012	7.236
PELFAC	FORECAST PRICES	4.111	4.275	4.422	4.538	4.690	4.729	4.815	5.307	6.210	7.588

TABLE B.5: ENERGY PRICES - THERMAL UNITS ($/GIGAJOULE) REGION: CANADA

		FORECAST								
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	ENERGY PRICE INDEXES (1981=1.0)										
PDIRAC	RESIDENTIAL	1.41	1.40	1.40	1.40	1.44	1.47	1.53	1.87	2.27	2.88
PDICPC	COMMERCIAL	1.43	1.44	1.47	1.46	1.51	1.53	1.58	1.89	2.29	2.91
PDIINC	INDUSTRIAL	1.38	1.35	1.36	1.34	1.37	1.39	1.45	1.85	2.26	2.83
PDITRC	TRANSPORTATION	1.43	1.28	1.31	1.26	1.28	1.32	1.40	1.84	2.22	2.72
PDISDC	TOTAL SECONDARY DEMAND	1.41	1.35	1.37	1.35	1.38	1.41	1.47	1.85	2.25	2.82
	REGIONAL SECTORAL PRICES: ($/GJ - EFFICIENCY ADJUSTED)										
PULFRC	LFO - RESIDENTIAL	15.25	12.35	11.41	10.62	10.82	11.28	12.16	17.01	21.23	26.67
PULFCC	- COMMERCIAL	12.12	9.92	9.14	8.45	8.61	8.94	9.61	13.38	16.89	21.36
PUHFIC	HFO - INDUSTRIAL	5.72	3.47	3.61	2.90	2.94	3.06	3.44	5.80	7.50	9.69
PUHFCC	- COMMERCIAL	6.32	3.81	3.87	3.20	3.26	3.40	3.82	6.38	8.19	10.55
PUNGRC	NATURAL GAS - RESIDENTIAL	7.55	7.61	7.59	7.53	7.67	7.84	8.35	11.41	14.75	19.08
PUNGCC	- COMMERCIAL	5.54	5.55	5.43	5.10	5.19	5.27	5.63	8.11	10.59	13.77
PUNGIC	- INDUSTRIAL	4.45	4.29	3.97	3.62	3.50	3.59	3.87	6.52	8.51	11.12
PUELRC	ELECTRICITY - RESIDENTIAL	12.08	12.53	13.02	13.33	13.83	13.96	14.22	15.76	18.44	23.11
PUELCC	- COMMERCIAL	15.28	15.84	16.46	16.87	17.45	17.61	17.94	19.74	23.11	29.01
PUELIC	- INDUSTRIAL	8.73	9.08	9.41	9.61	9.96	10.06	10.26	11.62	13.63	16.69
	PRICE RATIOS: (EFFICIENCY ADJ'D)										
	RESIDENTIAL:										
RPEORC	ELECTRICITY / LIGHT FUEL OIL	0.79	1.01	1.14	1.25	1.28	1.24	1.17	0.93	0.87	0.87
RPEGRC	ELECTRICITY / NATURAL GAS	1.60	1.65	1.72	1.77	1.80	1.78	1.70	1.38	1.25	1.21
RPOGRC	LIGHT FUEL OIL / NATURAL GAS	2.02	1.62	1.50	1.41	1.41	1.44	1.46	1.49	1.44	1.40
	COMMERCIAL:										
RPEOCC	ELECTRICITY / LIGHT FUEL OIL	1.26	1.60	1.80	2.00	2.03	1.97	1.87	1.48	1.37	1.36
RPEGCC	ELECTRICITY / NATURAL GAS	2.76	2.86	3.03	3.31	3.36	3.34	3.18	2.44	2.18	2.11
RPOGCC	LIGHT FUEL OIL / NATURAL GAS	2.19	1.79	1.68	1.66	1.66	1.70	1.71	1.65	1.59	1.55
	INDUSTRIAL:										
RPEOIC	ELECTRICITY / HEAVY FUEL OIL	1.53	2.62	2.61	3.32	3.39	3.29	2.98	2.00	1.82	1.72
RPEGIC	ELECTRICITY / NATURAL GAS	1.96	2.12	2.37	2.65	2.84	2.81	2.65	1.78	1.60	1.50
RPOGIC	HEAVY FUEL OIL / NATURAL GAS	1.29	0.81	0.91	0.80	0.84	0.85	0.89	0.89	0.88	0.87

TABLE 8.6: SUPPLY AND DEMAND - PETROLEUM
(THOUSANDS OF CUBIC METRES PER DAY)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	DOMESTIC CRUDE OIL PRODUCTION:										
VCRPN	TOTAL	249.9	250.1	259.1	259.4	251.9	247.7	233.0	212.0	248.6	258.0
QCROO	- CONVENTIONAL OLD OIL	106.3	87.5	77.6	69.7	59.6	52.5	46.1	26.2	12.6	5.5
QSOPN	- SYNTHETIC OIL	26.7	29.3	28.2	28.5	31.0	31.0	31.0	32.6	43.6	43.6
QCRER	- ENHANCED RECOVERY	17.7	20.7	20.4	17.6	15.5	14.9	13.2	14.7	24.0	33.5
QCRNT	- NEW OIL	99.2	112.6	132.9	143.6	146.3	150.3	143.7	139.5	169.4	176.4
QCRUN	- NET HEAVY UPGRADING	0.0	0.0	0.0	0.0	-0.5	-1.0	-1.0	-1.0	-1.0	-1.0
	DOMESTIC CRUDE OIL DEMAND:										
VRPDDC	PETROLEUM PRODUCTS DEMAND	220.5	223.5	231.5	237.7	239.6	243.2	249.2	267.7	293.4	317.7
VCRRG	REFINERY GAIN AND ADJUSTMENTS	9.6	12.6	12.8	12.9	13.0	13.0	13.1	13.5	14.0	14.5
QLPRN	NET REFINERY PROD'N OF LPG'S	1.2	2.1	2.0	1.2	1.2	1.2	1.2	1.2	1.2	1.2
QLPPR	- TOTAL REFINERY LPG PROD'N	6.1	6.0	6.0	6.1	6.1	6.1	6.1	6.1	6.1	6.1
VLPRP	- REFINERY LPG CONSUMPTION	4.9	3.9	4.0	4.9	4.9	4.9	4.9	4.9	4.9	4.9
VCRDD	DOMESTIC CRUDE OIL DEMAND	212.1	213.0	220.7	225.9	227.8	231.4	237.3	255.4	280.6	304.3
	STOCK CHANGE:										
VRPSC	REFINED PETROLEUM PRODUCTS	-5.7	-1.4	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VCRSC	CRUDE OIL	-1.4	-1.0	-0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	PETROLEUM EXPORTS:										
VPEXT	TOTAL	102.8	115.0	121.0	111.0	98.7	86.8	74.7	77.0	74.0	76.5
VCRXT	- CRUDE OIL - TOTAL	77.1	93.0	99.0	89.0	76.7	64.8	52.7	55.0	52.0	54.5
VLMXS	- LIGHT & MEDIUM	32.3	40.7	42.0	30.0	25.0	18.0	7.0	0.0	0.0	0.0
VHVXS	- HEAVY (INCL. DILUENT)	42.5	52.3	57.0	59.0	51.7	46.8	45.7	55.0	52.0	54.5
VCRXE	- EXCHANGES	2.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
VRPXT	- PRODUCTS - TOTAL	25.7	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0	22.0
	PETROLEUM IMPORTS:										
VPEMT	TOTAL	58.3	75.5	81.6	77.5	74.6	70.5	79.0	120.4	106.0	122.9
VCRMT	- CRUDE OIL	45.0	57.5	63.6	59.5	56.6	52.5	61.0	102.4	88.0	104.9
VRPMT	- PRODUCTS - TOTAL	13.3	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
VPEMN	NET PETROLEUM IMPORTS	-44.5	-39.5	-39.4	-33.5	-24.1	-15.3	4.3	43.4	32.0	46.3

TABLE B.7: SUPPLY & DEMAND - NATURAL GAS & LPG'S

		1985	FORECAST 1986	1987	1988	1989	1990	1991	1995	2000	2005
	MARKETABLE NATURAL GAS: (MCM)										
VNGPN	TOTAL PRODUCTION.....	77135.	71893.	77604.	83836.	85441.	87658.	90612.	103856.	113325.	121075.
VNGDD	DOMESTIC DEMAND.....	52472.	50222.	50020.	55478.	57082.	59300.	60837.	68415.	76468.	84218.
VNGSC	STOCK CHANGE.....	-1210.	1102.	-84.	400.	400.	400.	400.	400.	400.	400.
VNGXT	EXPORTS - ACTUAL.....	26153.	21090.	28032.	28329.	28329.	28329.	29745.	35411.	36827.	36827.
VNGMT	IMPORTS.....	5.	260.	93.	100.	100.	100.	100.	100.	100.	100.
VNGAJ	STATISTICAL ADJUSTMENT.....	276.	261.	272.	270.	270.	270.	270.	270.	270.	270.
	GAS PLANT LPG'S (KCM/D).....										
QLPRN	NET REFINERY PRODUCTION.....	1.20	2.12	2.00	1.20	1.20	1.20	1.20	1.20	1.20	1.20
VGPPN	GAS PLANT PROD (INCL SOLV FLD	40.43	39.73	43.33	46.45	49.34	51.34	52.48	50.97	47.59	45.81
VPBPN	PROPANE & BUTANE.....	26.37	25.56	25.63	26.65	26.54	26.54	26.68	26.17	24.79	23.01
QPBRS	FROM REPROCESSING PLANTS	7.50	7.25	8.00	8.00	8.00	8.00	8.00	7.00	7.00	6.00
VETPN	ETHANE.....	14.06	14.17	17.70	19.80	22.80	24.80	25.80	24.80	22.80	22.80
VGPDD	DOMESTIC DEMAND.....	21.83	22.83	25.76	25.19	26.01	29.45	31.62	40.48	44.47	48.23
VGPER	REQUIREMENTS FOR EOR PROJECTS	3.50	3.88	4.70	6.00	7.00	8.00	8.00	4.00	2.00	0.00
VGPSC	STOCK CHANGE.....	-1.18	2.71	2.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPAJ	STATISTICAL ADJUSTMENT.....	-0.25	0.17	-0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
VGPXT	EXPORTS.....	17.73	12.28	13.10	16.46	17.53	15.09	14.06	7.69	2.32	-1.22

TABLE B.8: ELECTRICITY SUPPLY & DEMAND
(GIGAWATT HOURS)

REGION: CANADA

		FORECAST								
	1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
	GENERATING CAPACITY (MEGAWATTS).									
KEGCTC	TOTAL	94888.	99486.	101484.	102552.	104978.	106211.	109538.	120405.	134786.	150629.
KEGCUC	UTILITIES	88666.	92265.	94249.	95287.	97692.	98812.	102116.	112718.	126967.	142754.
KEGCIC	INDUSTRIES	6222.	7221.	7235.	7265.	7286.	7399.	7422.	7687.	7819.	7875.
	CANGEN PLANNED GENERATION:									
	TOTAL:									
VEUPXC	UTILITIES	409413.	416391.	445277.	445137.	452201.	466784.	482429.	550735.	631850.	703804.
VEIPXC	INDUSTRY	37769.	39450.	40012.	40496.	40849.	41499.	41749.	43342.	45284.	45831.
	FOR DOMESTIC DEMAND:									
VELDXC	TOTAL	406859.	421864.	438378.	451536.	464285.	478798.	491071.	546559.	623879.	693731.
	CANGEN PLANNED CAPACITY FACTOR:									
RGCUPC	UTILITIES	0.527	0.515	0.539	0.533	0.528	0.539	0.539	0.558	0.568	0.563
RGCIPC	INDUSTRY	0.693	0.624	0.631	0.636	0.640	0.640	0.642	0.644	0.661	0.664
	EXTERNAL SALES & PURCHASES:									
VELENC	NET EXTERNAL SALES	40323.	33977.	46911.	34097.	28765.	29485.	33107.	47518.	53255.	55905.
VELXNC	NET EXPORTS TO U.S.	40323.	33977.	46911.	34097.	28765.	29485.	33107.	47518.	53255.	55905.
VELESC	EXTERNAL SALES	43016.	38935.	49925.	36189.	30857.	31577.	35199.	49610.	55347.	57997.
VELXTC	EXPORTS	43016.	38935.	49925.	36189.	30857.	31577.	35199.	49610.	55347.	57997.
VELEPC	EXTERNAL PURCHASES	2693.	4958.	3014.	2092.	2092.	2092.	2092.	2092.	2092.	2092.
VELMTC	IMPORTS	2693.	4958.	3014.	2092.	2092.	2092.	2092.	2092.	2092.	2092.
VELIRC	NET INTER-REGIONAL TRANSFERS	0.	0.	0.	1.	0.	0.	0.	1.	1.	1.
	GENERATION FOR DOMESTIC DEMAND: (INC. OWN-USE)									
VELDDC	TOTAL	406859.	422773.	438143.	451059.	463933.	477786.	490136.	544730.	620784.	691908.
VEUDDC	UTILITIES	369090.	383323.	398131.	410563.	423085.	436286.	448387.	501388.	575499.	646077.
VEIDDC	INDUSTRY	37769.	39450.	40012.	40496.	40849.	41499.	41749.	43342.	45284.	45831.
	TOTAL GENERATION:									
VELPNC	TOTAL	447182.	456750.	485054.	485157.	492698.	507271.	523243.	592249.	674040.	747814.
VEUPNC	UTILITIES	409413.	417300.	445042.	444661.	451850.	465771.	481494.	548907.	628755.	701983.
VEIPNC	INDUSTRY	37769.	39450.	40012.	40496.	40849.	41499.	41749.	43342.	45284.	45831.
	CAPACITY FACTOR:									
RGCUAC	UTILITIES	0.527	0.516	0.539	0.533	0.528	0.538	0.538	0.556	0.565	0.561
RGCIAC	INDUSTRY	0.693	0.624	0.631	0.636	0.640	0.640	0.642	0.644	0.661	0.664

TABLE B.9.1: SUMMARY RESULTS - ENERGY DEMAND REGION: CANADA
(PETAJOULES)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDC	SECONDARY DEMAND BY FUEL:	5996.0	6051.5	6135.1	6368.9	6544.1	6735.3	6906.1	7516.5	8250.9	9032.8
HRPSDC	RPP'S	2389.3	2416.7	2439.8	2521.5	2578.8	2639.6	2688.6	2858.2	3073.0	3359.2
HNGSDC	NATURAL GAS	1547.8	1505.4	1488.9	1569.6	1621.7	1686.9	1750.4	1952.2	2160.9	2364.5
HELSDC	ELECTRICITY	1336.1	1396.6	1447.0	1489.6	1532.0	1577.7	1618.5	1799.1	2049.9	2283.2
HCCSDC	COAL	51.2	49.8	54.0	57.4	59.6	60.1	60.5	60.1	60.4	67.0
HLPSDC	LPG'S	84.9	84.0	91.3	97.2	103.3	109.6	117.4	147.4	154.4	152.3
HKGSDC	COKE AND COKE OVEN GAS	187.3	178.3	187.6	195.5	202.7	210.9	216.3	230.7	250.1	271.2
HSTSDC	STEAM	34.0	32.2	34.7	38.3	40.2	39.8	39.7	37.5	45.9	54.2
HOFSDC	OTHER	365.5	388.5	391.9	399.9	405.7	410.8	414.5	431.3	456.1	481.1
	PRIMARY DEMAND BY SECTOR:										
HTSPDC	TOTAL	10016.1	10244.6	10548.3	10919.1	11212.4	11556.6	11872.5	13023.2	14492.2	15987.3
HTSEUC	END-USE DEMAND	6737.9	6713.5	6968.9	7218.9	7412.9	7635.9	7836.1	8526.7	9361.2	10266.8
HTSSDC	SECONDARY DEMAND	5996.0	6051.5	6135.1	6368.9	6544.1	6735.3	6906.1	7516.5	8250.9	9032.8
HTSRAC	RESIDENTIAL	1297.3	1284.6	1272.8	1319.4	1344.5	1382.2	1422.0	1532.1	1639.2	1726.3
HTSCPC	COMMERCIAL	903.6	903.6	915.0	963.2	1004.7	1047.0	1088.9	1237.4	1385.1	1512.0
HTSINC	INDUSTRIAL	2142.5	2198.2	2260.2	2380.5	2468.5	2549.6	2604.5	2811.7	3065.0	3380.4
HTSTRC	TRANSPORTATION	1652.6	1666.1	1687.2	1705.8	1726.4	1756.6	1790.7	1935.2	2161.5	2414.1
HTSNEC	NON-ENERGY USE	741.9	762.3	833.8	850.0	868.8	900.6	930.1	1010.3	1110.3	1233.9
HELIRC	INTER-REG'L ELEC. TRANSFERS.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HTSPCC	PRODUCER CONSUMPTION	434.3	417.3	437.2	476.4	491.2	508.8	525.3	582.0	657.7	720.1
HTSCLC	INTERMEDIATE CONVERSION LOSS	2843.7	3013.3	3142.1	3223.8	3308.2	3411.8	3511.1	3914.5	4473.3	5000.5
HTSPDC	PRIMARY DEMAND BY FUEL - TOTAL.	10016.1	10244.6	10548.3	10919.1	11212.4	11556.6	11872.5	13023.2	14492.2	15987.3
HRPPDC	RPP'S	3019.9	3054.1	3159.5	3256.6	3304.7	3382.5	3461.6	3654.2	4061.9	4400.0
HNGPDC	NATURAL GAS	1977.1	1952.3	1969.5	2108.2	2169.1	2253.4	2311.8	2599.8	2905.8	3200.3
HLPPDC	LPG'S	178.8	184.3	214.7	219.9	226.2	254.7	272.8	346.4	380.6	410.8
HCCPDC	COAL	1140.2	1031.7	999.0	1021.4	1049.6	1060.2	1188.2	1444.6	1695.1	1895.5
HENPDC	NUCLEAR ELECTRICITY	599.5	716.2	822.9	877.3	943.4	1007.2	1006.1	1136.2	1138.1	1248.8
HEHPDC	HYDRO ELECTRICITY	2734.3	2891.7	2964.2	3008.5	3084.9	3155.6	3183.4	3369.1	3807.7	4302.2
HOFPDC	OTHER (RENEWABLES)	365.7	414.0	418.5	427.1	434.5	442.9	448.6	473.0	503.1	529.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2C	PRIMARY DEMAND - TOTAL	7824.7	7884.3	8059.7	8365.5	8565.2	8821.0	9119.4	10062.6	11242.2	12339.5
HEHP2C	HYDRO ELECTRICITY	937.5	99..4	1016.3	1031.5	1057.7	1081.9	1091.4	1155.1	1305.5	1475.0
HENP2C	NUCLEAR ELECTRICITY	205.5	245.5	282.1	300.8	323.5	345.3	345.0	389.5	390.2	428.2
	RATIOS:										
RRDPHC	RES. DEMAND / HOUSEHOLD (GJ)	131.99	126.18	122.78	125.35	125.46	126.93	128.41	131.50	132.57	132.15
RCDPRC	COM. DEMAND / COM. RDP	5.04	4.77	4.57	4.69	4.79	4.89	4.97	5.17	5.16	5.02
RIDPRC	IND. DEMAND / IND. RDP	20.42	20.67	20.98	20.96	20.98	21.00	20.95	20.73	20.27	20.05
RSDPCC	SECONDARY DEMAND / POP (GJ).	236.51	236.40	237.32	244.00	248.35	253.28	257.58	272.10	289.59	309.48
RSDPRC	" / RDP/	18.46	18.00	17.72	17.81	17.82	17.89	17.95	17.91	17.63	17.31
REUPCC	END-USE DEMAND / POP (GJ)	265.77	260.69	269.57	276.56	281.32	287.14	292.27	308.67	328.56	351.75
REUPRC	" / RDP	20.74	19.85	20.12	20.18	20.18	20.28	20.37	20.31	20.00	19.68
RPDPCC	PRIMARY DEMAND / POP (GJ)	395.10	400.20	408.03	418.32	425.51	434.58	442.82	471.44	508.65	547.75
RPDPRC	" / RDP	31.12	30.46	30.45	30.53	30.53	30.70	30.86	31.03	30.97	30.64

TABLE B.9.2: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: ATLANTIC

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDF	SECONDARY DEMAND BY FUEL:	445.8	458.1	465.0	486.6	505.9	522.0	537.2	599.7	640.5	694.2
HRPSDF	RPP'S	291.9	293.0	296.3	309.0	320.4	330.5	339.3	372.9	389.4	409.6
HNGSDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15.5	32.6
HELSDF	ELECTRICITY	91.6	97.6	100.3	105.0	109.1	112.2	115.5	129.7	145.1	163.7
HCCSDF	COAL	3.1	2.4	2.9	4.1	5.2	6.2	7.1	10.2	5.9	4.6
HLPSDF	LPG'S	5.5	4.4	5.9	7.7	9.6	11.1	12.9	21.3	15.7	11.6
HKGSDF	COKE AND COKE OVEN GAS	3.1	9.8	10.1	10.3	10.5	10.8	10.9	11.5	12.4	13.1
HSTSDF	STEAM	6.7	1.4	0.2	0.3	0.3	0.4	0.4	0.6	0.4	0.4
HOFSDF	OTHER	43.8	49.4	49.2	50.1	50.7	50.9	51.1	53.1	56.1	58.6
	PRIMARY DEMAND BY SECTOR:										
HTSPDF	TOTAL	968.4	985.7	1007.3	1041.2	1049.5	1074.8	1157.5	1263.6	1362.9	1419.2
HTSEUF	END-USE DEMAND	463.9	475.4	484.1	506.8	526.9	543.7	559.5	623.7	666.7	722.3
HTSSDF	SECONDARY DEMAND	445.8	458.1	465.0	486.6	505.9	522.0	537.2	599.7	640.5	694.2
HTSRAF	RESIDENTIAL	85.2	84.9	87.2	92.1	96.7	100.9	104.8	114.8	117.0	123.2
HTSCPF	COMMERCIAL	62.8	61.9	63.0	66.6	70.3	72.2	74.9	87.2	92.1	100.1
HTSINF	INDUSTRIAL	151.5	165.2	166.1	175.2	182.6	188.0	192.7	216.1	227.8	246.1
HTSTRF	TRANSPORTATION	146.3	146.1	148.6	152.7	156.3	160.8	164.8	181.7	203.6	224.7
HTSNEF	NON-ENERGY USE	18.1	17.3	19.1	20.3	21.0	21.7	22.3	24.0	26.2	28.2
HELIRF	INTER-REG'L ELEC. TRANSFERS	273.1	246.7	249.1	253.9	238.1	238.3	286.5	289.1	303.7	260.7
HTSPCF	PRODUCER CONSUMPTION	32.2	36.0	32.4	33.1	32.8	33.9	36.0	40.5	42.7	45.9
HTSCLF	INTERMEDIATE CONVERSION LOSS	199.1	227.6	241.8	247.4	251.8	258.9	275.4	310.3	349.8	390.3
HTSPDF	PRIMARY DEMAND BY FUEL - TOTAL	968.4	985.7	1007.3	1041.2	1049.5	1074.8	1157.5	1263.6	1362.9	1419.2
HRPPDF	RPP'S	386.9	393.5	421.5	420.3	400.8	414.4	444.2	483.7	493.3	512.1
HNGPDF	NATURAL GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.8	16.8	34.6
HLPPDF	LPG'S	5.5	4.7	6.3	8.2	10.2	11.8	13.7	23.1	16.6	12.3
HCCPDF	COAL	88.9	86.2	86.4	101.2	108.2	111.7	128.9	191.8	219.7	225.7
HENPDF	NUCLEAR ELECTRICITY	57.0	54.9	53.1	46.6	46.5	46.5	46.6	46.6	46.5	47.8
HEHPDF	HYDRO ELECTRICITY	385.5	392.3	386.1	409.9	428.2	434.6	467.9	459.2	508.7	523.1
HOFPDF	OTHER (RENEWABLES)	43.8	53.6	54.0	54.9	55.5	55.8	56.1	58.3	61.3	63.8
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2F	PRIMARY DEMAND - TOTAL	676.8	691.4	718.7	741.2	737.5	758.7	819.3	931.2	998.0	1044.1
HEHP2F	HYDRO ELECTRICITY	132.2	134.5	132.4	140.6	146.8	149.0	160.4	157.4	174.4	179.4
HENP2F	NUCLEAR ELECTRICITY	19.5	18.8	18.2	16.0	16.0	16.0	16.0	16.0	15.9	16.4
	RATIOS:										
RRDPHF	RES. DEMAND / HOUSEHOLD (GJ)	110.86	108.18	108.74	112.87	116.62	120.03	122.85	129.03	124.77	127.52
RCDPRF	COM. DEMAND / COM. RDP	4.65	4.40	4.26	4.44	4.63	4.67	4.77	5.17	4.83	4.93
RIDPRF	IND. DEMAND / IND. RDP	29.40	31.38	31.82	32.31	33.01	33.64	34.27	35.50	33.63	33.33
RSDPCF	SECONDARY DEMAND / POP (GJ)	193.30	195.83	196.70	203.75	209.66	214.21	218.46	235.51	242.17	254.31
RSDPRF	" " / RDP/	21.55	21.59	21.44	21.84	22.15	22.23	22.43	23.05	22.06	22.61
REUPCF	END-USE DEMAND / POP (GJ)	201.13	203.23	204.77	212.23	218.36	223.10	227.54	244.93	252.09	264.63
REUPRF	" " / RDP	22.42	22.40	22.32	22.75	23.07	23.16	23.36	23.97	22.97	23.53
RPDPCF	PRIMARY DEMAND / POP (GJ)	419.87	421.38	426.14	435.99	434.97	441.05	470.68	496.19	515.33	519.95
RPDPRF	" " / RDP	46.80	46.45	46.45	46.74	45.95	45.78	48.32	48.57	46.95	46.24

TABLE 8.9.3: SUMMARY RESULTS - ENERGY DEMAND REGION: QUEBEC
(PETAJOULES)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDQ	SECONDARY DEMAND BY FUEL:	1280.9	1320.5	1352.4	1397.4	1444.4	1492.8	1534.4	1656.8	1820.7	2013.8
HRPSDQ	RPP'S	535.6	536.8	538.7	550.7	565.9	582.2	597.5	632.0	681.8	748.3
HNGSDQ	NATURAL GAS	183.7	185.5	192.3	204.2	214.9	225.6	235.5	271.2	305.1	334.9
HELSDQ	ELECTRICITY	478.1	502.4	524.4	545.4	564.9	584.6	598.6	642.7	712.3	799.4
HCCSDQ	COAL	14.6	14.1	17.6	16.4	15.4	14.6	13.7	11.1	10.0	10.2
HLPSDQ	LPG'S	12.0	9.4	5.7	5.6	6.4	7.0	9.2	16.8	24.1	28.8
HKGSDQ	COKE AND COKE OVEN GAS	0.5	2.3	2.5	2.6	2.7	2.9	2.9	3.1	3.3	3.6
HSTSDQ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDQ	OTHER	56.5	69.9	71.1	72.6	74.3	75.9	76.9	79.9	84.1	88.7
	PRIMARY DEMAND BY SECTOR:										
HTSPDQ	TOTAL	2268.1	2379.0	2490.9	2579.4	2664.8	2755.6	2778.1	3016.6	3494.3	4017.7
HTSEUQ	END-USE DEMAND	1363.9	1397.4	1447.0	1503.4	1559.5	1610.7	1654.6	1784.1	1955.8	2161.7
HTSSDQ	SECONDARY DEMAND	1280.9	1320.5	1352.4	1397.4	1444.4	1492.8	1534.4	1656.8	1820.7	2013.8
HTSRAQ	RESIDENTIAL	269.2	271.9	268.2	279.8	286.1	292.6	298.2	314.2	335.0	358.9
HTSCPQ	COMMERCIAL	152.0	178.3	182.6	193.9	204.7	213.6	224.7	258.1	297.5	331.5
HTSINQ	INDUSTRIAL	510.1	518.0	540.2	561.0	586.4	612.5	629.1	676.3	739.8	822.9
HTSTRQ	TRANSPORTATION	349.6	352.5	361.4	362.8	367.2	374.1	382.4	408.2	448.4	500.5
HTSNEQ	NON-ENERGY USE	83.0	76.9	94.6	106.0	115.0	117.9	120.2	127.2	135.1	147.9
HELIRQ	INTER-REG'L ELEC. TRANSFERS.	-182.6	-170.3	-161.0	-180.9	-197.0	-202.7	-257.1	-252.5	-109.9	2.7
HTSPCQ	PRODUCER CONSUMPTION	89.3	89.8	96.3	104.2	108.3	112.0	115.2	124.4	137.7	154.4
HTSCLQ	INTERMEDIATE CONVERSION LOSS	997.5	1062.1	1108.8	1152.8	1194.0	1235.6	1265.5	1360.7	1510.8	1698.8
HTSPDQ	PRIMARY DEMAND BY FUEL - TOTAL.	2268.1	2379.0	2490.9	2579.4	2664.8	2755.6	2778.1	3016.6	3494.3	4017.7
HRPPDQ	RPP'S	653.9	647.2	671.0	688.8	714.7	735.3	753.7	792.8	855.9	944.6
HNGPDQ	NATURAL GAS	185.3	186.8	202.0	214.3	225.1	236.0	246.1	282.4	317.0	347.3
HLPPDQ	LPG'S	17.5	13.7	17.7	11.8	12.8	13.5	16.3	32.7	44.1	53.5
HCCPDQ	COAL	21.5	22.8	26.6	25.5	24.9	24.4	23.7	21.5	21.0	21.8
HENPDQ	NUCLEAR ELECTRICITY	33.7	45.6	50.6	50.5	50.4	50.4	50.3	50.2	50.1	50.0
HEHPDQ	HYDRO ELECTRICITY	1299.8	1392.5	1459.9	1515.9	1562.6	1620.1	1611.1	1757.0	2122.0	2511.9
HOFPDQ	OTHER (RENEWABLES)	56.5	69.9	71.1	72.6	74.3	75.9	76.9	79.9	84.1	88.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Q	PRIMARY DEMAND - TOTAL	1391.9	1433.4	1498.3	1550.1	1604.8	1657.9	1686.3	1829.0	2066.9	2334.2
HEHP2Q	HYDRO ELECTRICITY	445.6	477.4	500.5	519.7	535.7	555.4	552.4	602.4	727.6	861.2
HENP2Q	NUCLEAR ELECTRICITY	11.6	15.6	17.4	17.3	17.3	17.3	17.3	17.2	17.2	17.1
	RATIOS:										
RRDPHQ	RES. DEMAND / HOUSEHOLD (GJ)	110.21	107.15	103.87	106.13	106.43	106.98	107.68	108 19	109.25	110.66
RCDPRQ	COM. DEMAND / COM. RDP	3.69	4.10	3.98	4.08	4.21	4.31	4.44	4.70	4.88	4.84
RIDPRQ	IND. DEMAND / IND. RDP	21.29	20.75	20.91	20.86	20.84	20.83	20.85	20.78	20.53	20.55
RSDPCQ	SECONDARY DEMAND / POP (GJ).	194.63	199.14	202.69	208.13	213.76	219.53	224.44	237.81	256.81	280.91
RSDPRQ	" / RDP/	17.29	17.16	16.94	16.88	16.92	16.98	16.99	16.97	16.86	16.74
REUPCQ	END-USE DEMAND / POP (GJ)	207.25	210.74	216.89	223.92	230.78	236.87	242.02	256.07	275.87	301.54
REUPRQ	" / RDP	18.41	18.16	18.13	18.16	18.27	18.32	18.32	18.27	18.11	17.97
RPDPCQ	PRIMARY DEMAND / POP (GJ)	344.65	358.78	373.34	384.18	394.35	405.24	406.37	432.99	492.87	560.44
RPDPRQ	" / RDP	30.61	30.92	31.20	31.15	31.21	31.34	30.76	30.90	32.36	33.4:

TABLE B.9.4: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: ONTARIO

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDO	SECONDARY DEMAND BY FUEL:	2170.3	2199.5	2245.1	2341.5	2412.8	2492.2	2566.6	2844.6	3143.7	3433.5
HRPSDO	RPP'S	745.6	764.0	770.9	798.8	818.8	842.6	857.1	916.0	969.2	1052.1
HNGSDO	NATURAL GAS	693.2	691.5	693.5	730.9	754.6	784.0	817.1	923.6	1016.9	1116.9
HELSDO	ELECTRICITY	405.8	427.9	443.5	456.2	469.5	484.3	501.4	587.8	697.8	767.1
HCCSDO	COAL	23.1	21.4	22 7	25.0	26.2	25.8	25.7	24.0	29.6	34.9
HLPSDO	LPG'S	25.2	28.8	35.6	38.3	41.6	45.1	48.7	62.0	68.2	67.3
HKGSDO	COKE AND COKE OVEN GAS	182.2	164.6	173.3	180.9	187.7	195.4	200.7	214.2	232.3	252.2
HSTSDO	STEAM	26.9	30.2	34.2	37.6	39.4	38.9	38.8	36.2	44.6	52.6
HOFSDO	OTHER	68.3	71.1	71.4	73.7	75.0	76.0	77.0	80.6	85.2	90.3
	PRIMARY DEMAND BY SECTOR:										
HTSPDO	TOTAL	3293.1	3372.9	3471.0	3641.8	3783.3	3912.9	4041.7	4551.6	4985.6	5395.7
HTSEUO	END-USE DEMAND	2405.8	2466.5	2530.0	2623.5	2700.0	2783.8	2862.5	3172.6	3499.3	3821.7
HTSSDO	SECONDARY DEMAND	2170.3	2199.5	2245.1	2341.5	2412.8	2492.2	2566.6	2844.6	3143.7	3433.5
HTSRAO	RESIDENTIAL	447.8	469.8	473.2	488.7	498.4	514.8	531.8	589.8	638.5	664.2
HTSCPO	COMMERCIAL	341.2	329.4	338.8	352.5	368.5	386.5	405.2	479.2	546.6	593.2
HTSINO	INDUSTRIAL	803.2	808.7	833.9	891.3	928.6	961.2	985.0	1076.4	1183.0	1312.9
HTSTRO	TRANSPORTATION	578.1	591.5	599.3	608.9	617.3	629.7	644.6	699.2	775.6	863.2
HTSNEO	NON-ENERGY USE	235.5	267.5	284.9	282.0	287.2	291.7	295.9	328.0	355.5	388.2
HELIRO	INTER-REG'L ELEC. TRANSFERS	-100.7	-84.1	-100.1	-86.5	-54.6	-51.1	-44.5	-53.6	-207.0	-277.1
HTSPCO	PRODUCER CONSUMPTION	160.6	161.0	164.0	183.3	190.1	197.6	203.5	226.7	265.5	286.6
HTSCLO	INTERMEDIATE CONVERSION LOSS	827.4	829.5	877.6	921.4	947.8	982.5	1020.1	1205.9	1427.8	1564.5
HTSPDO	PRIMARY DEMAND BY FUEL - TOTAL	3293.1	3372.9	3471.0	3641.8	3783.3	3912.9	4041.7	4551.6	4985.6	5395.7
HRPPDO	RPP'S	1019.9	1039.1	1077.1	1111.9	1138.3	1168.2	1186.8	1257.4	1484.6	1579.7
HNGPDO	NATURAL GAS	770.6	778.9	804.0	849.6	876.8	918.0	960.6	1093.6	1212.1	1331.7
HLPPDO	LPG'S	46.2	42.1	58.8	61.8	65.9	70.2	74.9	112.0	124.7	131.1
HCCPDO	COAL	539.6	452.5	393.1	445.7	461.3	450.7	513.8	647.7	714.5	724.4
HENPDO	NUCLEAR ELECTRICITY	508.8	615.6	719.1	780.2	846.5	910.3	909.1	1039.4	1041.5	1151.0
HEHPDO	HYDRO ELECTRICITY	339.7	368.6	369.4	317.3	317.8	317.3	317.0	317.9	319.7	383.0
HOFPDO	OTHER (RENEWABLES)	68.3	72.6	72.9	75.2	76.8	78.3	79.5	83.7	88.5	94.8
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2O	PRIMARY DEMAND - TOTAL	2735.5	2722.8	2756.2	2920.6	3018.3	3106.2	3235.9	3659.7	4091.1	4387.6
HEHP2O	HYDRO ELECTRICITY	116.5	126.4	126.7	108.8	108.9	108.8	108.7	109.0	109.6	131.3
HENP2O	NUCLEAR ELECTRICITY	174.5	211.1	246.6	267.5	290.2	312.1	311.7	356.4	357.1	394.6
	RATIOS:										
RRDPHO	RES. DEMAND / HOUSEHOLD (GJ)	132.89	135.18	132.82	133.79	133.42	134.93	136.56	141.09	143.13	140.32
RCDPRO	COM. DEMAND / COM. RDP	4.78	4.24	4.09	4.12	4.20	4.30	4.39	4.70	4.77	4.59
RIDPRO	IND. DEMAND / IND. RDP	16.41	15.97	16.31	16.39	16.50	16.63	16.61	16.60	16.33	16.12
RSDPCO	SECONDARY DEMAND / POP (GJ)	239.46	240.09	241.97	249.32	253.96	259.46	264.63	283.35	302.29	321.27
RSDPRO	" " / RDP/	16.47	15.93	15.71	15.82	15.82	15.90	15.97	16.11	15.91	15.48
REUPCO	END-USE DEMAND / POP (GJ)	265.45	269.20	272.69	279.36	284.19	289.83	295.15	316.02	336.47	357.60
REUPRO	" " / RDP	18.25	17.86	17.71	17.72	17.71	17.76	17.81	17.96	17.71	17.23
RPDPCO	PRIMARY DEMAND / POP (GJ)	363.35	368.17	378.90	387.79	398.22	407.38	416.73	453.39	479.39	504.87
RPDPRO	" " / RDP	24.99	24.43	24.43	24.60	24.81	24.96	25.15	25.77	25.23	24.32

TABLE B.9.6: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: MANITOBA

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDM	SECONDARY DEMAND BY FUEL:	214.7	213.0	210.5	217.7	221.9	227.4	233.2	257.6	288.3	323.6
HRPSDM	RPP'S	97.5	95.3	97.5	100.9	103.1	105.5	108.1	120.5	134.7	152.9
HNGSDM	NATURAL GAS	62.3	60.4	57.4	60.6	61.7	63.7	65.8	71.7	79.2	85.0
HELSDM	ELECTRICITY	48.7	50.2	49.7	49.6	49.6	50.1	50.7	54.6	62.7	71.9
HCCSDM	COAL	2.6	2.7	2.7	3.3	3.7	3.9	4.2	5.0	4.9	5.5
HLPSDM	LPG'S	3.1	3.6	2.5	2.6	3.0	3.3	3.6	4.6	5.6	6.8
HKGSDM	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDM	STEAM	0.3	0.4	0.3	0.4	0.4	0.5	0.5	0.7	0.9	1.1
HOFSDM	OTHER	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4
	PRIMARY DEMAND BY SECTOR:										
HTSPDM	TOTAL	367.9	370.5	367.0	380.4	386.0	395.8	403.6	443.5	493.4	554.9
HTSEUM	END-USE DEMAND	226.6	224.6	222.0	229.5	234.0	239.7	245.7	270.7	302.4	338.8
HTSSDM	SECONDARY DEMAND	214.7	213.0	210.5	217.7	221.9	227.4	233.2	257.6	288.3	323.6
HTSRAM	RESIDENTIAL	62.3	61.8	58.7	61.0	60.8	62.3	63.5	65.6	70.4	74.5
HTSCPM	COMMERCIAL	46.4	45.5	43.8	46.1	47.2	48.8	50.4	54.9	61.2	67.4
HTSINM	INDUSTRIAL	31.1	33.6	36.5	38.8	41.4	42.9	44.6	54.5	60.5	71.3
HTSTRM	TRANSPORTATION	74.9	72.0	71.4	71.9	72.5	73.5	74.7	82.5	96.1	110.5
HTSNEM	NON-ENERGY USE	11.9	11.6	11.5	11.8	12.0	12.3	12.5	13.2	14.1	15.1
HELIRM	INTER-REG'L ELEC. TRANSFERS	13.5	9.0	10.2	14.6	14.5	16.4	16.1	18.1	14.3	14.7
HTSPCM	PRODUCER CONSUMPTION	17.7	17.6	18.6	20.3	21.2	22.2	23.1	26.6	30.1	33.4
HTSCLM	INTERMEDIATE CONVERSION LOSS	110.1	119.3	116.2	116.0	116.2	117.4	118.6	128.0	146.7	168.1
HTSPDM	PRIMARY DEMAND BY FUEL - TOTAL	367.9	370.5	367.0	380.4	386.0	395.8	403.6	443.5	493.4	554.9
HRPPDM	RPP'S	102.5	99.9	102.2	105.8	108.3	110.9	113.7	126.8	141.9	161.2
HNGPDM	NATURAL GAS	79.2	77.7	73.8	78.6	80.6	83.6	86.5	95.0	104.2	111.5
HLPPDM	LPG'S	3.1	3.8	2.6	2.7	3.1	3.5	3.8	4.8	5.8	7.1
HCCPDM	COAL	7.0	5.7	5.6	6.3	6.8	7.1	7.4	8.5	8.6	9.6
HENPDM	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDM	HYDRO ELECTRICITY	175.8	182.9	182.2	186.3	186.5	190.1	191.7	207.7	232.2	264.9
HOFPDM	OTHER (RENEWABLES)	0.3	0.6	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2M	PRIMARY DEMAND - TOTAL	252.4	250.5	247.3	258.0	263.4	270.8	277.6	307.0	340.9	380.9
HEHP2M	HYDRO ELECTRICITY	60.3	62.7	62.5	63.9	63.9	65.2	65.7	71.2	79.6	90.8
HENP2M	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHM	RES. DEMAND / HOUSEHOLD (GJ)	135.21	127.98	117.91	121.06	117.46	117.79	117.77	115.53	117.18	118.41
RCDPRM	COM. DEMAND / COM. RDP	6.48	5.91	5.42	5.56	5.58	5.66	5.73	5.69	5.70	5.58
RIDPRM	IND. DEMAND / IND. RDP	12.45	12.66	13.57	13.91	14.24	13.86	14.12	14.87	15.10	15.11
RSDPCM	SECONDARY DEMAND / POP (GJ)	200.72	197.45	193.14	197.49	199.41	202.55	206.16	223.28	246.86	275.46
RSDPRM	" / RDP/	16.76	15.96	15.43	15.41	15.31	15.27	15.27	15.27	15.40	15.26
REUPCM	END-USE DEMAND / POP (GJ)	211.81	208.21	203.72	208.17	210.22	213.49	217.18	234.70	258.94	288.33
REUPRM	" / RDP	17.69	16.83	16.27	16.24	16.14	16.09	16.09	16.05	16.16	15.97
RPDPCM	PRIMARY DEMAND / POP (GJ)	343.92	343.51	336.73	345.08	346.77	352.47	356.72	384.43	422.54	472.33
RPDPRM	" / RDP	28.73	27.76	26.89	26.92	26.63	26.56	26.42	26.29	26.37	26.17

TABLE B.9.6: SUMMARY RESULTS - ENERGY DEMAND (PETAJOULES) REGION: SASKATCHEWAN

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDS	SECONDARY DEMAND BY FUEL:	283.4	273.7	270.1	279.9	285.2	292.4	298.2	319.7	357.6	405.2
HRPSDS	RPP'S	125.6	123.4	121.1	123.5	125.2	127.1	128.5	134.5	149.4	170.0
HNGSDS	NATURAL GAS	102.2	94.4	90.9	98.2	102.2	107.4	111.8	123.6	135.4	147.2
HELSDS	ELECTRICITY	36.8	37.6	39.1	38.5	37.8	37.7	37.7	40.8	49.7	61.7
HCCSDS	COAL	4.3	3.0	4.0	4.4	4.7	5.1	5.4	5.9	6.8	8.4
HLPSDS	LPG'S	4.8	4.6	4.2	4.0	3.6	3.2	2.9	2.4	2.9	3.6
HKGSDS	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDS	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDS	OTHER	9.7	10.8	10.8	11.4	11.7	11.9	12.0	12.5	13.4	14.4
	PRIMARY DEMAND BY SECTOR:										
HTSPDS	TOTAL	433.5	409.2	417.0	425.5	431.0	440.2	448.0	486.4	559.2	651.2
HTSEUS	END-USE DEMAND	294.6	285.5	280.5	291.1	297.1	304.8	311.2	334.0	374.6	425.2
HTSSDS	SECONDARY DEMAND	283.4	273.7	270.1	279.9	285.2	292.4	298.2	319.7	357.6	405.2
HTSRAS	RESIDENTIAL	91.1	89.9	87.6	91.1	93.2	95.8	97.3	102.4	109.9	118.8
HTSCPS	COMMERCIAL	41.0	39.8	40.8	44.2	44.1	44.6	44.7	46.2	49.1	53.5
HTSINS	INDUSTRIAL	75.3	70.8	69.0	72.2	75.0	78.2	81.4	88.7	101.3	119.0
HTSTRS	TRANSPORTATION	76.0	73.1	72.7	72.4	73.0	73.8	74.8	82.3	97.3	113.9
HTSNES	NON-ENERGY USE	11.2	11.8	10.5	11.3	11.9	12.4	12.9	14.3	17.0	20.0
HELIRS	INTER-REG'L ELEC. TRANSFERS	-3.4	-1.4	1.8	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0	-1.0
HTSPCS	PRODUCER CONSUMPTION	29.3	27.0	28.3	31.6	33.3	35.1	36.9	43.4	48.8	54.1
HTSCLS	INTERMEDIATE CONVERSION LOSS	113.0	98.1	106.4	103.7	101.7	101.3	101.0	110.0	136.8	172.9
HTSPDS	PRIMARY DEMAND BY FUEL - TOTAL	433.5	409.2	417.0	425.5	431.0	440.2	448.0	486.4	559.2	651.2
HRPPDS	RPP'S	141.6	138.9	136.1	139.3	141.7	144.1	146.1	153.8	171.9	196.2
HNGPDS	NATURAL GAS	126.1	119.9	118.0	128.6	134.4	141.4	147.5	165.1	180.8	195.8
HLPPDS	LPG'S	4.9	4.6	4.2	4.0	3.6	3.2	2.9	2.4	2.9	3.6
HCCPDS	COAL	131.5	94.2	106.8	101.0	98.3	98.1	97.9	111.0	148.3	198.3
HENPDS	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDS	HYDRO ELECTRICITY	19.6	39.4	39.5	39.6	39.7	39.7	39.7	39.7	39.7	40.1
HOFPDS	OTHER (RENEWABLES)	9.7	12.4	12.4	12.9	13.4	13.7	13.9	14.4	15.6	17.2
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2S	PRIMARY DEMAND - TOTAL	420.6	383.4	391.0	399.5	404.9	414.1	421.9	460.3	533.1	624.8
HEHP2S	HYDRO ELECTRICITY	6.7	13.5	13.5	13.6	13.6	13.6	13.6	13.6	13.6	13.7
HENP2S	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHS	RES. DEMAND / HOUSEHOLD (GJ)	171.91	158.30	151.61	156.54	156.34	158.24	159.36	165.89	170.85	175.88
RCDPRS	COM. DEMAND / COM. RDP	7.24	6.74	6.63	7.08	6.86	6.83	6.73	6.43	6.01	5.65
RIDPRS	IND. DEMAND / IND. RDP	29.41	30.04	29.33	27.71	27.33	27.53	27.92	28.38	28.23	28.40
RSDPCS	SECONDARY DEMAND / POP (GJ)	278.75	264.52	257.26	263.25	264.85	268.09	270.34	277.64	296.31	322.09
RSDPRS	" " / RDP/	23.49	22.01	21.49	21.74	21.49	21.54	21.53	21.42	21.18	20.82
REUPCS	END-USE DEMAND / POP (GJ)	289.76	275.97	267.24	273.84	275.92	279.46	282.06	290.09	310.43	337.98
REUPRS	" " / RDP	24.42	22.96	22.32	22.61	22.39	22.45	22.46	22.38	22.19	21.85
RPDPCS	PRIMARY DEMAND / POP (GJ)	426.36	395.51	397.22	400.18	400.25	403.58	406.12	422.44	463.38	517.57
RPDPRS	" " / RDP	35.93	32.90	33.18	33.04	32.47	32.42	32.34	32.59	33.13	33.46

TABLE 8.9.7: SUMMARY RESULTS - ENERGY DEMAND REGION: ALBERTA
(PETAJOULES)

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDA	SECONDARY DEMAND BY FUEL:	792.9	793.8	792.0	821.2	834.6	853.5	868.0	925.6	1012.5	1087.8
HRPSDA	RPP'S	295.5	307.6	310.7	321.9	322.7	323.8	326.9	342.8	379.9	416.9
HNGSDA	NATURAL GAS	340.4	326.0	313.1	328.7	339.6	353.9	363.4	391.4	424.5	451.0
HELSDA	ELECTRICITY	111.3	114.9	120.8	122.6	125.0	128.6	130.6	145.0	162.5	176.0
HCCSDA	COAL	1.7	1.4	1.6	1.3	1.2	1.1	1.0	0.6	0.1	0.1
HLPSDA	LPG'S	24.7	22.7	24.9	25.1	24.1	23.8	23.4	21.8	20.1	17.8
HKGSDA	COKE AND COKE OVEN GAS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HSTSDA	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDA	OTHER	19.1	21.1	20.9	21.6	22.0	22.4	22.7	24.0	25.4	26.1
	PRIMARY DEMAND BY SECTOR:										
HTSPDA	TOTAL	1460.1	1488.6	1528.4	1575.1	1596.6	1648.1	1689.6	1828.4	2019.2	2204.3
HTSEUA	END-USE DEMAND	1133.6	1122.1	1155.7	1187.3	1201.2	1242.3	1278.2	1374.4	1516.9	1658.0
HTSSDA	SECONDARY DEMAND	792.9	793.8	792.0	821.2	834.6	853.5	868.0	925.6	1012.5	1087.8
HTSRAA	RESIDENTIAL	218.0	192.2	186.6	192.0	193.5	197.2	205.0	219.0	236.9	249.7
HTSCPA	COMMERCIAL	152.0	145.2	143.6	151.2	157.1	164.2	169.2	180.9	196.5	213.5
HTSINA	INDUSTRIAL	198.2	234.9	241.1	255.3	259.0	264.2	263.9	273.0	292.3	308.4
HTSTRA	TRANSPORTATION	224.7	221.6	220.7	222.7	224.9	228.0	230.9	252.7	286.8	316.3
HTSNEA	NON-ENERGY USE	340.8	328.1	363.7	366.1	366.6	388.8	410.2	448.8	504.4	570.2
HELIRA	INTER-REG'L ELEC. TRANSFERS.	-0.4	0.7	-5.6	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7	-4.7
HTSPCA	PRODUCER CONSUMPTION	53.3	59.0	59.4	63.0	64.0	65.3	66.4	72.0	79.3	86.3
HTSCLA	INTERMEDIATE CONVERSION LOSS	273.5	306.9	318.9	329.5	336.1	345.1	349.8	386.7	427.7	464.8
HTSPDA	PRIMARY DEMAND BY FUEL - TOTAL	1460.1	1488.6	1528.4	1575.1	1596.6	1648.1	1689.6	1828.4	2019.2	2204.3
HRPPDA	RPP'S	371.7	387.5	392.5	413.7	416.2	418.5	422.1	437.6	480.9	525.2
HNGPDA	NATURAL GAS	616.5	585.9	592.0	657.4	669.8	678.2	658.7	720.2	796.0	871.9
HLPPDA	LPG'S	91.9	104.6	118.4	117.2	115.2	136.2	144.2	153.2	168.3	186.5
HCCPDA	COAL	346.2	361.0	376.3	336.9	345.0	363.0	411.3	458.8	510.1	555.7
HENPDA	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDA	HYDRO ELECTRICITY	14.6	19.0	18.9	18.9	18.4	18.3	18.3	17.8	17.3	17.9
HOFPDA	OTHER (RENEWABLES)	19.1	30.6	30.3	31.1	32.0	33.8	35.1	40.7	46.5	47.2
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2A	PRIMARY DEMAND - TOTAL	1450.4	1476.1	1516.0	1562.7	1584.5	1636.0	1677.6	1816.7	2007.8	2192.6
HEHP2A	HYDRO ELECTRICITY	5.0	6.5	6.5	6.5	6.3	6.3	6.3	6.1	5.9	6.1
HENP2A	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHA	RES. DEMAND / HOUSEHOLD (GJ)	223.94	183.34	176.85	184.97	185.64	188.62	191.55	195.35	193.99	192.71
RCDPRA	COM. DEMAND / COM. RDP	8.26	7.82	7.45	7.80	8.01	8.24	8.31	8.12	7.87	7.69
RIDPRA	IND. DEMAND / IND. RDP	18.08	22.95	24.11	23.91	23.42	22.96	22.35	20.71	19.84	19.80
RSDPCA	SECONDARY DEMAND / POP (GJ)	336.36	339.49	337.90	348.99	353.10	358.98	362.93	375.29	394.02	408.66
RSDPRA	" / RDP/	22.11	22.44	22.25	22.59	22.68	22.90	23.05	22.35	21.95	21.51
REUPCA	END-USE DEMAND / POP (GJ)	480.92	472.20	493.05	504.58	508.21	522.51	534.43	557.25	590.30	622.85
REUPRA	" " / RDP	31.61	31.22	32.46	32.66	32.65	33.33	33.95	33.18	32.88	32.78
RPDPCA	PRIMARY DEMAND / POP (GJ)	619.42	636.40	653.70	669.37	675.47	693.15	706.48	741.33	785.76	828.10
RPDPRA	" " / RDP	40.71	42.07	42.93	43.33	43.39	44.22	44.87	44.14	43.77	43.58

TABLE B.9.8: SUMMARY RESULTS - ENERGY DEMAND
(PETAJOULES)

REGION: B.C.+YK.+N.W.T.

		FORECAST									
		1985	1986	1987	1988	1989	1990	1991	1995	2000	2005
HTSSDZ	SECONDARY DEMAND BY FUEL:	808.2	793.0	800.2	824.6	839.3	854.9	868.5	912.4	987.6	1074.6
HRPSDZ	RPP'S	297.5	296.8	304.7	316.7	322.7	327.8	331.3	339.6	368.7	409.5
HNGSDZ	NATURAL GAS	165.9	147.6	141.6	147.0	148.7	152.3	156.8	170.6	184.2	197.0
HELSDZ	ELECTRICITY	163.9	165.9	169.3	172.3	176.0	180.3	184.1	198.4	220.0	243.4
HCCSDZ	COAL	1.9	4.7	2.5	3.0	3.2	3.3	3.4	3.2	3.2	3.4
HLPSDZ	LPG'S	9.6	10.5	12.4	13.8	15.1	16.1	16.7	17.9	17.8	16.5
HKGSDZ	COKE AND COKE OVEN GAS	1.5	1.6	1.7	1.7	1.7	1.8	1.8	1.9	2.1	2.2
HSTSDZ	STEAM	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HOFSDZ	OTHER	168.0	165.9	168.2	170.2	171.8	173.3	174.5	180.9	191.7	202.6
	PRIMARY DEMAND BY SECTOR:										
HTSPDZ	TOTAL	1224.7	1219.1	1241.1	1275.7	1301.2	1329.2	1354.0	1433.1	1577.7	1744.2
HTSEUZ	END-USE DEMAND	849.7	839.0	849.4	877.2	894.3	910.8	924.5	967.2	1045.5	1139.0
HTSSDZ	SECONDARY DEMAND	808.2	793.0	800.2	824.6	839.3	854.9	868.5	912.4	987.6	1074.6
HTSRAZ	RESIDENTIAL	123.7	114.0	111.2	114.7	115.8	118.5	121.4	126.3	131.5	137.0
HTSCPZ	COMMERCIAL	108.4	103.4	102.5	108.8	112.9	117.1	120.7	130.9	142.1	152.9
HTSINZ	INDUSTRIAL	373.2	367.0	373.3	386.7	395.4	402.6	407.8	426.8	460.2	499.8
HTSTRZ	TRANSPORTATION	202.8	209.2	213.1	214.4	215.2	216.8	218.6	228.5	253.8	285.0
HTSNEZ	NON-ENERGY USE	41.5	46.0	49.2	52.6	55.1	55.8	56.0	54.8	57.9	64.4
HELIRZ	INTER-REG'L ELEC. TRANSFERS	0.3	-0.7	5.5	4.7	4.7	4.7	4.7	4.7	4.7	4.7
HTSPCZ	PRODUCER CONSUMPTION	51.9	43.2	38.2	40.9	41.6	42.6	44.2	48.3	53.7	59.4
HTSCLZ	INTERMEDIATE CONVERSION LOSS	322.7	337.6	348.0	352.9	360.6	371.0	380.6	412.9	473.7	541.1
HTSPDZ	PRIMARY DEMAND BY FUEL - TOTAL	1224.7	1219.1	1241.1	1275.7	1301.2	1329.2	1354.0	1433.1	1577.7	1744.2
HRPPDZ	RPP'S	343.4	348.1	359.1	376.7	384.7	391.1	395.0	402.1	433.4	481.2
HNGPDZ	NATURAL GAS	199.4	179.5	179.6	179.7	182.4	196.2	212.5	242.6	278.8	307.5
HLPPDZ	LPG'S	9.7	10.8	12.6	14.1	15.4	16.4	17.0	18.2	18.1	16.8
HCCPDZ	COAL	5.5	9.2	4.3	4.8	5.1	5.3	5.3	5.2	73.0	160.0
HENPDZ	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
HEHPDZ	HYDRO ELECTRICITY	499.2	497.0	508.4	520.7	531.7	535.5	537.6	569.7	568.0	561.3
HOFPDZ	OTHER (RENEWABLES)	168.0	174.3	177.2	179.8	182.0	184.7	186.5	195.2	206.4	217.4
	ELECTRICITY CONVERTED AT 3.6:										
HTSP2Z	PRIMARY DEMAND - TOTAL	897.0	892.3	907.1	933.6	951.8	977.3	1000.7	1058.7	1204.5	1375.3
HEHP2Z	HYDRO ELECTRICITY	171.2	170.4	174.3	178.5	182.3	183.6	184.3	195.3	194.7	192.5
HENP2Z	NUCLEAR ELECTRICITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	RATIOS:										
RRDPHZ	RES. DEMAND / HOUSEHOLD (GJ)	106.95	97.53	94.09	96.77	96.86	98.28	99.70	100.84	100.15	98.91
RCDPRZ	COM. DEMAND / COM. RDP	5.30	4.66	4.41	4.70	4.80	4.88	4.93	4.95	4.79	4.59
RIDPRZ	IND. DEMAND / IND. RDP	36.33	35.79	35.45	35.87	35.96	36.00	35.98	35.05	33.68	32.76
RSDPCZ	SECONDARY DEMAND / POP (GJ)	273.22	262.95	262.01	266.85	268.47	270.60	272.20	276.46	289.37	306.44
RSDPRZ	" / RDP/	21.53	20.39	19.99	20.02	19.97	20.08	20.19	19.71	19.12	18.61
REUPCZ	END-USE DEMAND / POP (GJ)	287.25	278.20	278.30	283.87	286.08	288.27	289.76	293.07	306.35	324.79
REUPRZ	" / RDP	22.63	21.57	21.22	21.30	21.28	21.39	21.50	20.80	20.24	19.72
RPDPCZ	PRIMARY DEMAND / POP (GJ)	414.10	404.25	406.39	412.82	416.26	420.69	424.37	434.24	462.27	497.36
RPDPRZ	" / RDP	32.65	31.35	31.00	30.97	30.96	31.22	31.48	30.96	30.54	30.20